PRIMEWEST

2005
ANNUAL REPORT

PrimeWest Energy Trust

INVESTING FOR LONG-TERM VALUE

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbls	Barrels
bcf	Billion cubic feet
BOE	Barrel of oil equivalent
BOE/day	Barrel of oil equivalent per day
bbls/day	Barrels per day
mWhr	Megawatt-hour
mbbls	Thousand barrels
mmbbls	Million barrels
mmBOE	Million barrels of oil equivalent
mmbtu	Million British thermal units
mmcf	Million cubic feet
mcf	Thousand cubic feet
tcf	Trillion cubic feet

CONVERSION FACTORS

1 cubic metre (liquids) = 6.29 barrels

1 cubic metre (natural gas) = 35.49 cubic feet

1 litre = 0.22 Imperial gallons

1 hectare = 2.47 acres

1 cubic metre = 1,000 litres

1 mcf of natural gas = 1.055 gigajoules of natural gas = 1 mmbtu

PrimeWest Energy Trust is a Calgary-based conventional oil and natural gas royalty trust that acquires, develops, produces and sells natural gas, crude oil and natural gas liquids to generate monthly cash distributions for Unitholders. The Trust was formed in 1996 and today is one of North America's largest natural gas-weighted energy trusts. The Trust's operations are focused in the Western Canada Sedimentary Basin.

Trust Units of PrimeWest are traded on the Toronto Stock Exchange (TSX) under the symbol "PWI.UN" and on the New York Stock Exchange (NYSE) under the symbol "PWI". Exchangeable Shares of PrimeWest Energy Inc. trade on the TSX under the symbol "PWX". The Five-Year Convertible Debentures of PrimeWest trade on the TSX under the symbol "PWI.DB.A" and the Seven-Year Convertible Debentures trade under the symbol "PWI.DB.B".

www.primewestenergy.com

THE ANNUAL GENERAL AND SPECIAL MEETING of the Unitholders of PrimeWest Energy Trust will be held on May 4, 2006 at 10:30 a.m. local time at the Metropolitan Conference Centre, 333-Fourth Avenue S.W., Calgary, Alberta. All Unitholders and interested parties are invited to attend.

PrimeWest has incorporated cost-saving initiatives in this annual report. Unitholders are encouraged to visit our website at www.primewestenergy.com for current updates on our operations.

All figures in this annual report are in Canadian dollars, unless otherwise indicated.

Strategies For Value-Creation

VALUE-CREATION	Value-creation is the key driver of all aspects of PrimeWest's operations, including acquisitions, development and infrastructure improvements. Through our active development program, we replaced 100% of our reserves produced during 2005.
FINANCIAL MANAGEMENT	PrimeWest adheres to financial strategies allowing us to manage distributions, fund our development opportunities and manage debt levels and taxability of cash flows within a volatile commodity price environment. During 2005 our balance sheet strengthened as our debt to cash flow ratio was reduced to 0.8 times, down from 1.7 times at the end of 2004. In December 2005, the Trust's Board of Directors declared a 20% increase in the monthly distribution payment to $0.36 per Trust Unit.
DEVELOPMENT PORTFOLIO	PrimeWest has established an asset base consisting of four strategic play types that provide an opportunity base with which to add new reserves and production. The four strategic play types are tight gas, Southeast Alberta shallow gas, conventional development and an emerging coalbed methane play. PrimeWest strives to operate the majority of its assets in each of its core areas, which provides operating flexibility, efficient operations and cost control capabilities. In 2005, PrimeWest invested a record $186 million of development capital in its four strategic play types.
CORPORATE GOVERNANCE	Sound corporate governance practices are integral to the success of PrimeWest. Integrity is a critical element of success and is essential to maintaining the confidence of our Unitholders. PrimeWest is a reporting issuer in Canada and is listed on the TSX and the NYSE. The Canadian Securities Commissions and the NYSE have established guidelines and standards regarding corporate governance for listed companies. We remain in material compliance with the NYSE and the requirements of Canadian securities laws. We are also working toward Sarbanes-Oxley compliance (SOX) and expect to certify on the adequacy and effectiveness of the Trust's internal control structure as of December 31, 2006.

Financial And Operating Highlights

		2005	2004
FINANCIAL HIGHLIGHTS *($ millions, except per BOE (1) and Trust Unit amounts)*	Gross revenue, net of transportation expense	$ 749.7	$ 513.7
	Per BOE	50.90	39.45
	Cash flow from operations	414.1	266.8
	Per BOE	28.11	20.49
	Per Trust Unit (2)	5.46	4.49
	Royalty expense	172.8	119.8
	Per BOE	11.73	9.20
	Operating expense	117.0	88.9
	Per BOE	7.94	6.83
	Cash general and administrative expense	22.9	19.0
	Per BOE	1.56	1.46
	Non-cash general and administrative expense (3)	5.4	4.1
	Per BOE	0.37	0.32
	Interest expense (4)	28.3	20.6
	Per BOE	1.92	1.58
	Distributions to Unitholders	276.6	196.1
	Per Trust Unit (5)	3.66	3.30
	Net debt (6)	323.7	552.0
	Per Trust Unit (7)	$ 3.97	$ 7.77
OPERATING HIGHLIGHTS *(results as per units indicated)*	AVERAGE DAILY PRODUCTION		
	Natural gas (mmcf/day)	178.2	145.1
	Crude oil (bbls/day)	6,861	8,282
	Natural gas liquids (bbls/day)	3,797	3,107
	Total (BOE/day)	40,351	35,578
	AVERAGE SELLING PRICES		
	Natural gas ($/mcf)	$ 8.43	$ 6.61
	Crude oil ($/bbl)	49.05	36.83
	Natural gas liquids ($/bbl)	55.92	43.69
	Combined oil equivalent (8) ($/BOE)	$ 50.81	$ 39.35
	Realized hedging loss included in prices above ($/BOE)	$ (3.01)	$ (2.16)
	COMPANY INTEREST PROVED PLUS PROBABLE RESERVES (9)		
	Natural gas (bcf)	677.3	677.9
	Crude oil (mbbls)	23,646	23,903
	Natural gas liquids (mbbls)	18,068	18,270
	Total Oil Equivalent (mmBOE)	154.6	155.2
	Reserve Life Index (10)	11.0 years	10.3 years

(1) All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to one barrel of crude oil. BOE may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

(2) The basic per Trust Unit calculation includes the weighted average Trust Units outstanding and Trust Units issuable upon exchange of the outstanding Exchangeable Shares of PrimeWest Energy Inc.

(3) Non-cash general and administrative expense has been restated to reflect the change in method of accounting for the Trust's unit-based compensation. See Note 3 to the Consolidated Financial Statements.

(4) Interest expense includes the interest on the Convertible Unsecured Subordinated Debentures.

(5) Based on Trust Units outstanding on the Record Date.

(6) Net debt is long-term debt, including Convertible Unsecured Subordinated Debentures, less working capital, excluding financial derivative assets and liabilities and current future income tax assets.

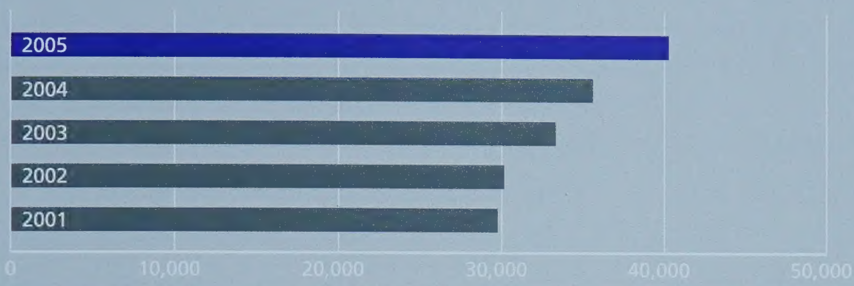
(7) The net debt per Trust Unit calculation includes outstanding Trust Units, Trust Units issuable upon exchange of the outstanding Exchangeable Shares and Trust Units issuable pursuant to the Long-Term Incentive Plan (LTIP) at the end of the period.

(8) Includes realized hedging losses.

(9) Company Interest reserves include the Trust's working interest share and royalties receivable, before deduction of royalties payable.

(10) The 2005 Reserve Life Index is calculated as total oil equivalent reserves (mmBOE) divided by the average daily production forecast for the coming year.

AVERAGE DAILY PRODUCTION (BOE/day)

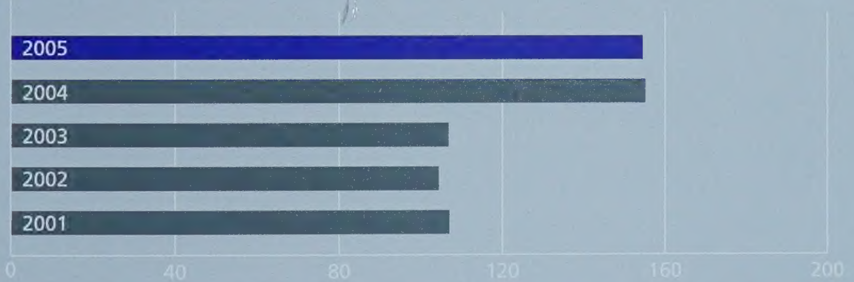


From 2001 to 2005, PrimeWest's average production grew by 36%, from 29,700 BOE/day to over 40,300 BOE/day. Production has become more heavily weighted to natural gas, which PrimeWest believes has excellent long-term Unitholder value potential. Through 2006, production is projected to average 38,000-39,000 BOE/day.

CASH FLOW FROM OPERATIONS ($ millions)

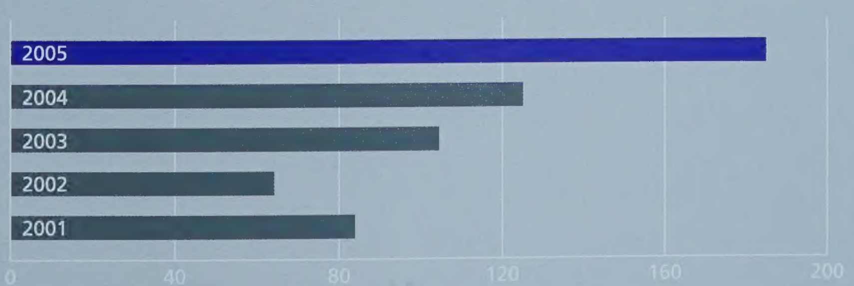
PrimeWest's cash flow from operations increased by 55% over 2004 to $414 million in 2005. A combination of high commodity prices and increased production contributed to record-level cash flows.

COMPANY INTEREST PROVED PLUS PROBABLE RESERVES (mmBOE)



Year-end reserves have grown by 44% since 2001. The Trust's Reserve Life Index of 11.0 years reflects a balance between maximizing current cash flow and sustaining production over the longer term.

DEVELOPMENT CAPITAL ($ millions)



From 2001 to 2005, PrimeWest invested approximately $570 million in developing its asset base. During 2005, PrimeWest invested a record $186 million its development programs. The Trust has identified development opportunities of approximately $800 million to pursue over the next several years.

Management's Letter To Unitholders

> Strong Unit price performance and record cash flow of $414 million resulted in total returns for the year of 51.4% for Canadian Unitholders and 56.6% for U.S. Unitholders.

In 2005, PrimeWest continued to follow prudent financial management practices while investing a record level of development capital in our asset base. Following the successful integration of the Calpine acquisition completed in 2004, we organized our development teams to better align our resources to key development plays within our expanded asset base. We continued to build on our development portfolio for future years, to enhance the future stability of the Trust.

During 2005, we continued to implement our strategy, achieving the following results:

- Achieved production in line with our guidance at an average rate of 40,351 BOE/day, weighted 74% to natural gas;
- Delivered record cash flow from operations of $414 million;
- Announced a 20% increase in distributions to $0.36 per Trust Unit, approved by the Board of Directors in December and effective with the December distribution paid on the January 13, 2006 distribution payment date;
- Achieved average operating costs of $7.94/BOE of production, which is expected to be competitive among the larger Canadian energy trusts in a period of industry-wide cost increases;
- Executed the largest development program in PrimeWest's history, with development capital totaling $186 million, which included the drilling of 132 gross wells and adding 14.7 mmBOE of Proved plus Probable reserves after revisions, representing production replacement of 100%;
- Launched the Distribution Reinvestment Program to U.S. Unitholders in September 2005;
- Reduced net debt from $552 million at the end of 2004 to $324 million at the end of 2005; and
- Delivered a one-year total return for Canadian Unitholders of 51.4% and for U.S. Unitholders of 56.6%.

Financial Strength

Throughout 2005, PrimeWest continued to see reductions in our debt level as a result of strong cash flows and the conversion of $187 million of convertible debentures into equity. At the end of 2005 we had approximately $334 million of unutilized credit available with our bank syndicate. Our net debt ratio was reduced from 1.7 times annual cash flow at the beginning of the year to 0.8 times annual cash flow at year-end.

As we enter 2006, PrimeWest has strength in its balance sheet, which provides the financial flexibility to fund our development program and to pursue acquisition opportunities as they arise. We will continue to follow financial management practices that balance the interests of our Unitholders while providing the flexibility to pursue accretive acquisition opportunities to increase Unitholder value.

Total Returns and Distributions

PrimeWest's primary objective is to maximize long-term total returns for our Unitholders. As of year-end 2005, our five-year compound average annual total return (the combination of cumulative distributions reinvested and changes to the Unit price) was 19% in Canada and 25.3% in the U.S. In 2005, PrimeWest achieved a one-year total return of 51.4% in Canada and a one-year total return of 56.6% for U.S. Unitholders.

PrimeWest enters 2006 with a Proved plus Probable Reserve Life Index of 11.0 years and development opportunities of approximately $800 million to pursue over the next several years. The distribution level was increased in December 2005 by 20% from $0.30 per Trust Unit per month to $0.36 per Trust Unit per month, based on commodity price levels in effect at the time, coupled with PrimeWest's prudent risk management strategy. PrimeWest follows a strategy of maintaining a distribution payout ratio of approximately 70-90% of cash flow from operations on an annual basis recognizing that during periods of volatile commodity prices, the payout ratio may temporarily move outside of this range.

In September 2005, PrimeWest launched the conventional portion of the Distribution Reinvestment Program (DRIP) to Unitholders resident in the U.S. Subject to brokerage house participation, the plan allows U.S. Unitholders to reinvest their distribution payment, net of Canadian withholding tax, into Trust Units of PrimeWest at a 5% discount to the volume-weighted average price, with no brokerage fees or commissions. Since the launch of the program, U.S. participation has contributed approximately 15% to the DRIP.

In 2005, we reinvested 45% of our cash flow in further developing our asset base. This investment resulted in 100% replacement of reserves produced during the year.

Asset Management

PrimeWest's asset management strategy is to focus on its existing core areas and pursue depletion optimization strategies to maximize value. We control approximately 80% of our assets with the balance controlled by partner operators. This level of control allows us to use our existing infrastructure and create synergies within our core areas. It also allows us to control our costs and plan the timing of our capital investments and projects.

High commodity prices in 2005 led to record acquisition costs. While our acquisitions and divestitures team continually screens and evaluates acquisition opportunities in the market, we maintain the position that we will only grow through value-creating acquisitions. We carefully evaluate prospective opportunities against a set of established criteria, ensuring that any acquisition we pursue is profitable for the Trust. The challenge in identifying a value-creating acquisition in this high commodity price environment reinforces our greater emphasis on pursuing internal development opportunities as a means of sustaining our production base. Our internal development opportunities reduce the reliance on acquisitions to maintain production levels and mitigate natural declines.

The high commodity prices in 2005 also created intense levels of competition for field services and materials. This competition increased prices in the field, where we experienced cost pressures on both capital and operating expenses of 10-20%. However, our size, scale and financial position allowed us to compete effectively for field services. Long-term contracts that we have in place with a number of our field contractors allowed us to plan our long-term development projects and realize cost savings through field efficiencies.

PrimeWest invested a record $186 million of development capital in 2005, which created attractive Unitholder returns in adding new production volumes and reserves. Our 11.0-year Reserve Life Index is near the average of our senior Canadian royalty trust peer group, creating a balance between long-term sustainability and current cash flow. Looking forward, we have a sizeable opportunity base for future internal development. These development opportunities continue to evolve as we develop the asset base and gain a greater understanding of the unique characteristics of our properties. Sustained investment in these opportunities is expected to add to our production and reserves in future years.

In recognition of the trust sector's importance in the Canadian capital markets, PrimeWest and other trusts were added to the S&P/TSX Composite Index in December 2005.

Hedging

As part of the financial management strategy, PrimeWest's hedging strategy is designed to reduce the volatility of cash flow by providing some near-term downside price protection. Hedging a portion of our production protects acquisition economics and our capital structure and provides partial protection against short-term declines in commodity prices. In recent months we have been emphasizing the use of wide costless collars in our hedging program. These costless collars provide us with downside price protection should commodity prices decline, while allowing participation in a portion of the upside in pricing. As commodity prices increase beyond the ceiling price of the costless collar, the opportunity cost is recorded as a loss for accounting purposes.

During 2005, these opportunity costs totalled $43.5 million. Approximately $16 million of the hedging losses were the result of natural gas hedges that were put in place during August and September 2004 to protect acquisition economics related to the Calpine transaction. Reflecting the pricing environment at the time of the acquisition, costless collars were put in place with lower price ceilings in return for robust price protection on the downside. All of the Calpine hedges will expire after the first quarter of 2006. We expect our hedging results in 2006 to reflect the emphasis on utilizing wider costless collars, resulting in the Trust's participation in potential pricing upside.

PrimeWest's management and Board of Directors evaluate the Trust's hedging strategy carefully and believe hedging remains an important tool to partially reduce commodity price risk, protect acquisition economics and provide protection to debt levels. For 2006, we have hedged approximately 2,700 bbls/day of our crude oil production and approximately 50 mmcf/day of our natural gas production before royalties. (Further details are provided on page 33).

Industry Events

On January 26, 2005, Standard & Poor's (S&P) and the TSX jointly announced the intention to include income trusts in the S&P/TSX Composite Index. The index inclusion process was to occur over two stages. The first stage took place on December 16, 2005, with 50% of the freely traded units of the listed trusts, including PrimeWest, added to the index. The second stage, set to take place in March 2006, will include the remaining 50%. PrimeWest's weighting in the index at the first stage was approximately 0.116% as of January 31, 2006. The inclusion of the trust sector in the index is reflective of the current realities and size of the Canadian income trust sector, now in excess of $170 billion of market capitalization.

On September 8, 2005, the then Government of Canada issued the long-awaited consultation paper regarding the income trust sector. PrimeWest participated in the consultation process and was pleased with the subsequent announcement on November 23, 2005 that there would be no additional tax applied to the trust sector. The then Minister of Finance announced an effective reduction in the personal income tax on dividend income, reducing the double taxation of corporate dividends. This decision removed the uncertainty that was affecting the trust sector during the third quarter of 2005. The proposed change in taxation on corporate dividends would better align the dividend tax treatment with the tax treatment of income trust distribution payments.

2006 Outlook and Plans

PrimeWest enters 2006 with reduced debt levels from 2004, an inventory of development opportunities of approximately $800 million and a Reserve Life Index of 11.0 years. We have developed strengths in our core areas that provide a competitive advantage in creating new value within our portfolio of producing assets. We have diligently contained costs in an inflationary environment and have achieved competitive operating costs in the Canadian energy trust sector. We have substantial tax pools of more than $1.3 billion, a high level relative to our peer group, which will help to shelter our retained cash flows and distributions from taxation. During times of sustained high commodity prices, tax pools erode more quickly than during times of lower commodity prices. The inventory of development opportunities in our core areas provides the ability to partially mitigate decline in our production base without having to rely extensively on acquisitions. If an accretive acquisition opportunity that satisfies our internal criteria presents itself, we are in a strong financial position, with our excellent access to the capital markets, to complete such a transaction, whether it is of a small or large scale.

We will continue to build on our operating strengths throughout 2006. This year's internal capital development program is budgeted at $275 million, which will fund drilling of approximately 200 gross wells. We estimate 2006 production to average 38,000–39,000 BOE/day.

Entering 2006 our monthly distribution rate to Unitholders has been raised to $0.36 per Trust Unit. We continue to target a long-term payout ratio of approximately 70-90% of cash flow, recognizing the potential for short-term exceptions to this range depending on commodity price movement. This consistent approach to distributions provides us with capital to partially fund our development program and creates greater certainty for our Unitholders in a volatile commodity-price market.

In closing, I would like to extend my thanks and appreciation to all our employees for their continued hard work throughout the year. As we embark on a new year of record activity levels, I believe that through the combination of the skills and capabilities of our employees and a solid team approach to our work, we will succeed in achieving our goals and adding value for our Unitholders. The management team of PrimeWest extends its thanks to each and every one of our employees.

Sincerely,

Don Garner

DON GARNER
President and Chief Executive Officer

February 23, 2006

In 2006, we will continue to invest in the development of our asset base, including drilling 200 gross wells.

Letter From The Chair

Fellow Unitholders of PrimeWest:

PrimeWest's Board of Directors and management team are committed to achieving high standards of corporate governance. Corporate governance is more than a statement of corporate office protocol. At PrimeWest, governance practices have been adopted throughout the organization, including head office and field settings. It is our view that effective corporate governance should include specific reporting structures and business processes, as well as a strategic plan and a commitment to implement the plan. We believe that effective corporate governance contributes to Unitholder value and to the ongoing trust and confidence of the marketplace in PrimeWest.

The Board of Directors of PrimeWest Energy Inc. is ultimately responsible for the stewardship of PrimeWest Energy Inc. including the business affairs of PrimeWest Energy Trust. The Board consists of eight members, all of whom are considered independent for the purposes of the rules of the NYSE and the Canadian Securities Commissions applicable generally to the Board of Directors and for the purposes of the rules applicable to each director's membership on the various committees established by the Board. The Board's committee structure consists of the Audit and Finance Committee, Compensation Committee, Corporate Governance and EH&S Committee, and the Operations and Reserves Committee. For complete disclosure of our independence determinations, please refer to the Management Proxy Circular issued with the notice of the 2006 annual general and special meeting and in the Corporate Governance section of our website at www.primewestenergy.com.

The Board of Directors and management are closely aligned in implementing PrimeWest's business strategies. The Board and management meet regularly and also hold a meeting at least annually to specifically review and evaluate the business strategy and to review and develop plans for executing the strategy.

PrimeWest is listed on the TSX and the NYSE, and the Canadian Securities Commissions and the NYSE have established guidelines and standards regarding corporate governance for listed companies. Although the NYSE rules, with the exception of those applicable to the audit committee, are not mandatory for a "foreign private issuer" like PrimeWest, we remain in material compliance with the NYSE rules and the corporate governance requirements of the recently passed National Policy 58-201 and National Instrument 58-101 of the Canadian Securities Commissions.

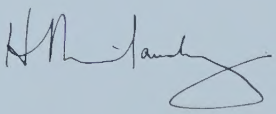
Reinforcing the rules and guidelines mandated by the Canadian Securities Commissions and the NYSE are the provisions of the Sarbanes-Oxley Act of 2002 (SOX), which directed the U.S. Securities and Exchange Commission (SEC) to develop more stringent internal control mechanisms for all capital markets participants. As a non-U.S., SEC 40-F issuer, PrimeWest has until the end of 2006 to fully comply with certain mandated requirements of SOX. During 2005, PrimeWest continued the implementation process of the required SOX provisions, with the expectation of being in full compliance by the end of 2006 and in order to prepare for the anticipated implementation of parallel Canadian legislation.

Consistent with these policies and proposals, PrimeWest's framework of corporate governance, including any significant ways in which our practices differ from those followed by U.S. domestic companies under the NYSE rules, is fully discussed in the Management Proxy Circular and in the Corporate Governance section of our website at www.primewestenergy.com.

PrimeWest remains committed to high standards of corporate governance and to compliance with all existing rules and proposals that have been adopted but not yet implemented. We believe that integrity is a critical element, central to the long-term success of PrimeWest and essential to maintain the confidence of our loyal Unitholder base.

Unitholders and other interested parties wishing to communicate with any of the directors of PrimeWest are invited to send private and confidential correspondence to PrimeWest Energy Trust, Suite 5100, 150-6th Avenue S.W., Calgary, Alberta T2P3Y7, Attention: Chair/Presiding Director. Correspondence will be delivered, unopened to the Chair/Presiding Director of the Board.

Sincerely,



HAROLD P. MILAVSKY, FCA

Chair of the Board

February 23, 2006

Review Of Operations

2005 Average Production (BOE/day)	40,351
2005 Year-end Company Interest Proved plus Probable Reserves (mmBOE)	154.6
2006 Development Capital Budget ($ millions)	275
2006 Drilling Plans (projected number of gross wells)	195-225
2006 Projected Production	38,000-39,000

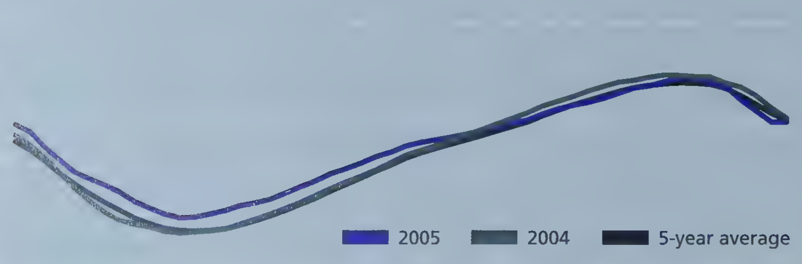
As an actively managed energy trust, PrimeWest creates value for Unitholders through acquiring, developing and producing reserves, expanding its assets and facilities and improving operating efficiencies in the field.

The Natural Gas Market

HISTORICAL NATURAL GAS PRICES ($/mcf)

Increased pipeline takeaway capacity, continued growth in North American natural gas demand and the difficult challenge of increasing supply in a mature basin have resulted in western Canadian natural gas prices rising from below $2.00/mcf in 1996 to over $10.00/mcf by 2005 year-end. While there has recently been weather-related softening in natural gas prices, we remain bullish on the long-term outlook for natural gas.

WEEKLY U.S. GAS STORAGE LEVELS (bcf)



2005 began with North American natural gas storage well above the previous year's levels. Over the ensuing hot summer, this storage overhang was gradually worked off by strong electricity demand for cooling purposes. Hurricanes Katrina and Rita severely reduced the volumes of natural gas that could be injected into storage prior to winter, which caused prices to spike to historically high levels. By 2005 year-end, gas storage had dropped to levels approaching the five-year average.

Western Canada's efficient pipeline system moves natural gas to major consuming centres in eastern Canada and in the U.S., including the Midwest and California.

Since 2000, PrimeWest has evolved into a natural gas-weighted producer through the pursuit of economic acquisition opportunities. In 2001, the acquisition of Cypress Energy Inc. boosted PrimeWest's natural gas weighting to 59% from 50% in the previous year. Subsequent significant acquisitions included the Caroline/Peace River Arch property transactions in 2003, and the Seventh Energy and Calpine acquisitions in 2004. All of these transactions were heavily weighted towards natural gas assets. In 2005, approximately 74% of PrimeWest's production consisted of natural gas. When natural gas liquids are included in the gas ratio, gas assets account for almost 85% of PrimeWest's production base.

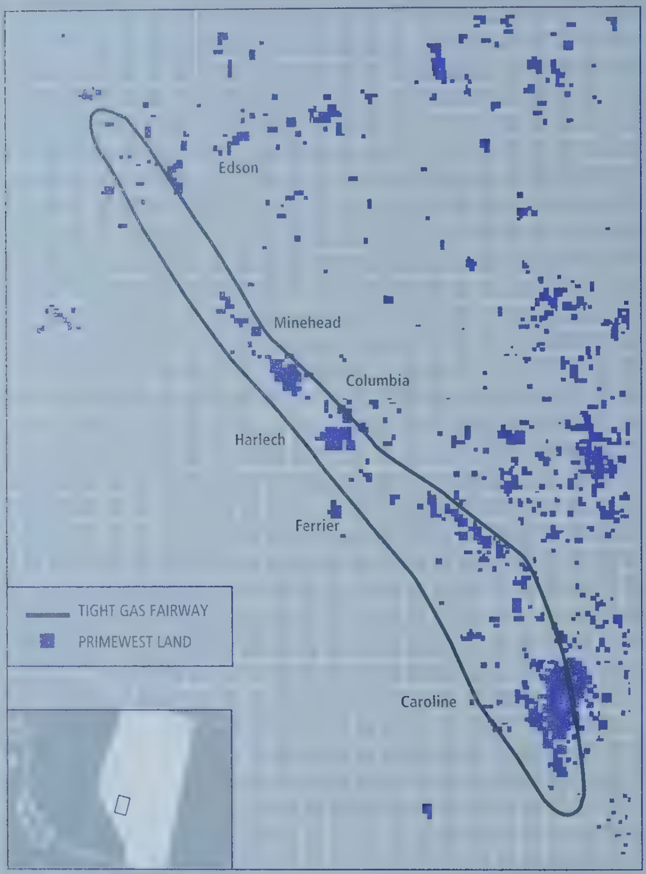
Natural gas prices reached a record level in 2005, and the year-end forward price curve suggested that prices could be even higher in 2006. Despite the softening in prices during the first quarter of 2006, our view of longer-term natural gas prices remains bullish. We see natural gas supply-demand fundamentals as being very favourable to producers going forward. North American demand for natural gas should now be more resilient compared to the last price spike during 2000/2001, as a result of many of the price-sensitive natural gas users exiting the market over the past few years.

On the supply side, overall North American production has remained flat despite intensive drilling activities over the last few years. As the main supply basins mature, the opportunity to find new natural gas fields with large production capability has become more rare and costly. The majority of the new natural gas wells drilled and brought on production in the last few years had smaller associated reserves and lower initial production rates than the natural gas wells of the past. Major new supply, in the form of either natural gas from Northern Canada/Alaska, or increased LNG imports from offshore sources is, in our opinion, several years away. This bodes very well for short- and medium-term natural gas prices. Investors should always keep in mind that a regional weather event can impact prices for brief periods, as we saw in 2005 after hurricanes interrupted production in the Gulf of Mexico and natural gas prices reached a peak of US$15.38/mmbtu on December 13, 2005.

Crude oil prices were strong throughout 2005, due to a combination of strong global demand growth and supply concerns caused by many factors. Current forward markets indicate that oil prices should remain high in 2006. This should provide continued support for strong natural gas prices.

Natural gas prices reached record levels during 2005, contributing to record cash flow for PrimeWest. We remain bullish for the long-term outlook for natural gas in the North American market.

Tight Gas



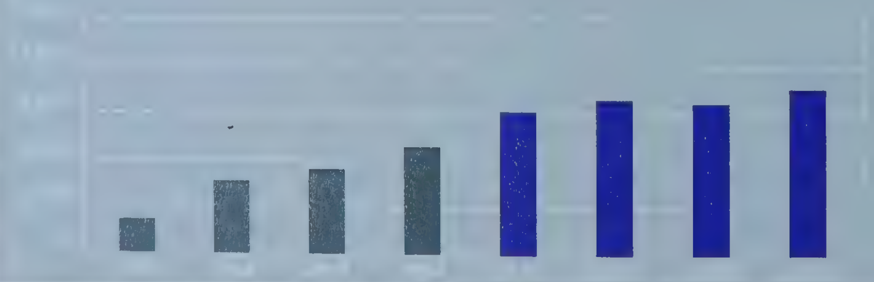
Tight Gas

The multi-zone development strategy employed in these key areas includes primary development targets in the Viking and Cardium formations at depths of between 2,500 and 3,000 metres. Production profiles associated with these types of wells consist of high initial production rates that decline to a lower but nearly stabilized rate, providing the Trust with years of steady, long-life, low-decline production.

Quick Facts

PRIMARY COMMODITY:	Sweet natural gas with natural gas liquids
MAIN PROPERTIES:	Caroline, Columbia, Ferrier, Edson, Harlech, Minehead
2005 AVERAGE PRODUCTION:	9,777 BOE/day
YEAR-END 2005 RESERVES:	41.4 mmBOE Proved plus Probable
2005 CAPITAL INVESTED:	$82 million
2005 DRILLING:	27 gross wells
SUCCESS RATE:	100%
2006 DEVELOPMENT CAPITAL:	$70-80 million
2006 PLANNED DRILLING:	35-40 gross wells
2006 AVERAGE PRODUCTION TARGET:	9,400 BOE/day

PRIMEWEST TIGHT GAS PRODUCTION (BOE/day)



Infill and extension development drilling at Caroline and Columbia provided quarter-over-quarter growth in natural gas production volumes throughout 2005.

Investing in Tight Gas

PrimeWest's deeper tight gas fields in West Central Alberta continue to provide the Trust with strategic development opportunities over the next several years in the key operating areas of Caroline/Ferrier, Columbia/Harlech/Minehead and Edson.

The multi-zone development strategy employed in these key areas includes primary development targets in the Viking and Cardium formations at depths of between 2,500 and 3,000 metres. There are also several other prospective zones including the Belly River, Mannville Group and Banff formations. These liquids-rich sandstone pools are considered "tight" due to the relatively low permeability of the reservoirs, which often requires fracture stimulation to initiate production. These tight reservoirs have smaller drainage areas than conventional reservoirs, requiring additional downspacing of wells and infill drilling to access all of the hydrocarbon reserves. This provides opportunities for low-risk development and production additions. Production profiles typical for these wells begin with high initial flush production rates that quickly drop off to a lower, more stabilized rate, generally lasting for years. This type of profile provides the Trust with steady, long-life, low-decline production. Levering off several acquisitions, PrimeWest has established a core development foothold in the Caroline and Columbia areas where the Trust operates and controls most of the natural gas processing and gathering infrastructure. In 2005, PrimeWest supplemented its existing land base with a Crown land acquisition. Combined with its undeveloped land base and development drilling inventory, controlling the pace of development and access to the take-away capacity in the area enables the Trust to pursue opportunities to add production volumes while controlling its capital and operating costs – a key factor in ensuring the profitability of these tight gas resource plays.

At Caroline, 2005 production averaged approximately 5,700 BOE/day. The 2003 acquisition of the 100%-owned natural gas processing plant and the implementation of other field efficiencies have contributed to the reduction of average operating costs from $7.00-8.00/BOE of production to approximately $4.00/BOE, adding $3.00-4.00 in value to every BOE of throughput. The Caroline plant also generates third-party processing fees for the Trust. At Columbia, 2005 production was approximately 2,000 BOE/day.

In May 2006, approximately 8,500 BOE/day will be shut-in at Caroline and Edson for plant turnarounds. The full-year impact on volumes due to these planned turnarounds is expected to be 300 BOE/day.

Future Opportunities

PrimeWest's continued expansion of its tight gas play provides the Trust with a significant inventory of multi-zone drilling prospects to add low-risk production and reserves over the next several years from more than 135,000 net acres of undeveloped land. In 2006, PrimeWest will increase drilling to a combined 35-40 gross wells at Caroline/Ferrier, Columbia/Harlech/Minehead and Edson. PrimeWest has identified more than 100 wells and $400 million of development drilling opportunities in these tight gas areas.

Our tight gas play provides multi-zone, low risk development potential, providing long-life, low decline production.

Southeast Alberta Shallow Gas

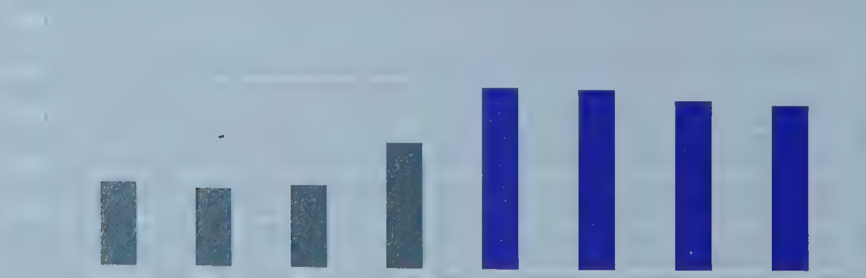
Southeast Alberta Shallow Gas

PrimeWest's shallow gas plays provide the Trust with low-risk development drilling opportunities. Our land holdings and ownership of natural gas gathering and processing facilities at Brant Farrow, Princess/Dinosaur, Bindloss and Medicine Hat create a competitive advantage for our development drilling.

Quick Facts

PRIMARY COMMODITY:	Sweet, dry natural gas
MAIN PROPERTIES:	Brant Farrow, Princess/Dinosaur, Bindloss, Medicine Hat
2005 AVERAGE PRODUCTION:	5,495 BOE/day
YEAR-END 2005 RESERVES:	19.2 mmBOE Proved plus Probable
2005 CAPITAL INVESTED:	$19.5 million
2005 DRILLING:	22 gross wells
SUCCESS RATE:	100%
2006 DEVELOPMENT CAPITAL:	$30-35 million
2006 PLANNED DRILLING:	60-70 gross wells
2006 AVERAGE PRODUCTION TARGET:	5,100 BOE/day

PRIMEWEST SOUTHEAST ALBERTA SHALLOW GAS PRODUCTION (BOE/day)



Development activity in 2005 focused on exploiting the Glauconitic channel trends at Brant Farrow, providing a relatively flat production profile quarter-over-quarter by offsetting the natural declines of producing shallow gas pools at Princess/Dinosaur, Bindloss and Medicine Hat.

Investing In Shallow Gas

PrimeWest's core strategic shallow gas plays in Southeast Alberta provide the Trust with very low-risk development drilling opportunities through downspacing and infill drilling in the Medicine Hat, Milk River and Second White Specs formations. Our large-scale land holdings and ownership of the low-pressure natural gas gathering and processing facilities at Brant Farrow, Princess/Dinosaur, Bindloss and Medicine Hat create a competitive advantage for our development drilling. By exploiting these pools lying at shallow depths of approximately 700 metres, we are able to drill multi-well programs that take advantage of cost savings from repeatability and economies of scale.

In 2005, PrimeWest utilized 3-D seismic to delineate the deeper, more prolific Glauconitic pools underlying the existing shallow gas plays. Additional potential exists in the Colony and Basal Colorado formations. At depths of approximately 1,000 metres, wells producing from these deeper pools can produce at 1 mmcf/day per successful well, adding to our overall volumes from this region.

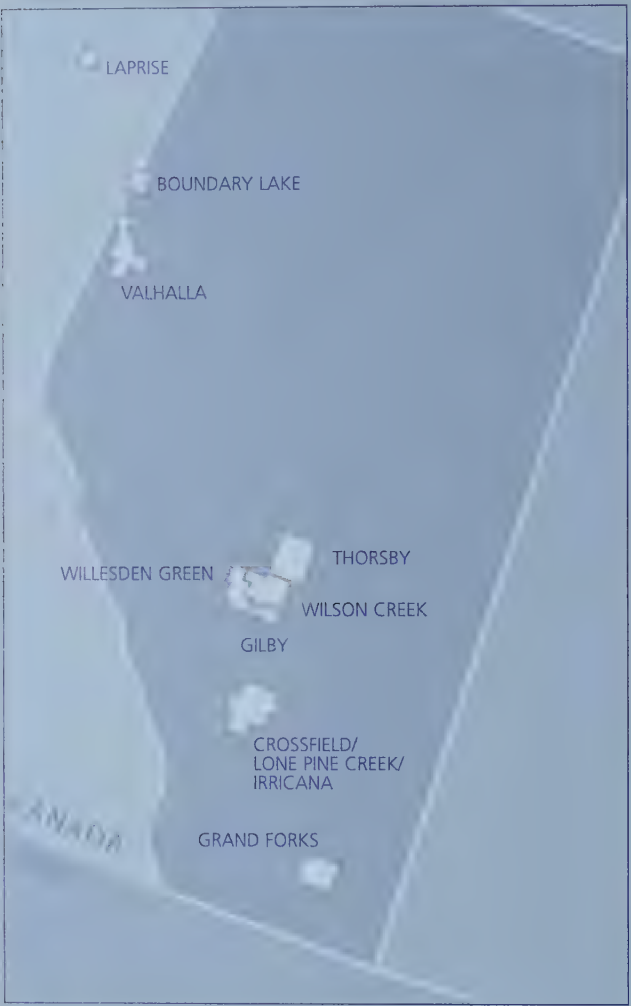
PrimeWest's development approach provides a combination of long-life, low-rate production from the shallower gas pools plus higher-rate, shorter-life production generating strong cash flow and rapid payout from the deeper prospects, while maintaining an overall low risk level. Production from these key shallow gas plays and deeper targets averaged just under 5,500 BOE/day in 2005.

This play represents a combination of long-life, low-rate production from shallow wells and higher-rate, shorter-life production from the deeper pools.

Future Opportunities

With more than 128,000 net acres of undeveloped lands at year-end 2005, PrimeWest is well positioned to develop its reserves and add production from its Southeast Alberta shallow gas plays. In 2006, PrimeWest plans to drill 60-70 gross wells, with a goal of maintaining overall production volumes. The Trust's current program includes investing up to $35 million to drill downspaced wells at a density of up to eight wells per section in several of our key shallow gas areas.

Conventional Development



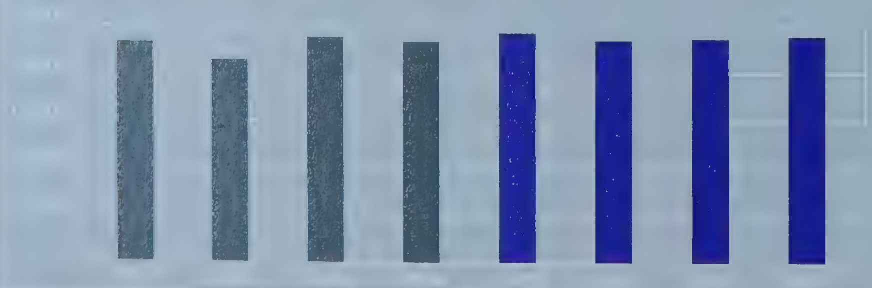
Conventional Development

PrimeWest continues to develop its low-risk conventional plays. The Trust has more than 250,000 net acres of undeveloped land and can lever off its existing facility infrastructure.

Quick Facts

PRIMARY COMMODITY:	Natural gas and natural gas liquids, conventional light sweet crude oil
MAIN PROPERTIES:	Laprise, Boundary Lake, Valhalla, Thorsby, Wilson Creek, Crossfield/Lone Pine Creek/Irricana, Grand Forks
2005 AVERAGE PRODUCTION:	23,743 BOE/day
YEAR-END 2005 RESERVES:	89.6 mmBOE Proved plus Probable
2005 CAPITAL INVESTED:	$81 million
2005 DRILLING:	66 gross wells
SUCCESS RATE:	97%
2006 DEVELOPMENT CAPITAL:	$100-110 million
2006 PLANNED DRILLING:	90-100 gross wells
2006 AVERAGE PRODUCTION TARGET:	22,500 BOE/day

PRIMEWEST CONVENTIONAL PRODUCTION (BOE/day)



Development drilling successes at Wilson Creek and Crossfield/Lone Pine Creek offset the natural decline of the conventional development assets in 2005. Production from Q4 2005 drilling at Valhalla and Laprise is planned to be brought on stream in early 2006.

Investing in Conventional Development

PrimeWest continues to invest in development opportunities at its conventional plays, which include key properties at Wilson Creek, Crossfield/Lone Pine Creek/Irricana, Valhalla, Laprise, Boundary Lake and Grand Forks. In 2005, capital expenditures of $81 million were comprised of $54 million for drilling, completions, equipping and tie-in, $8 million for land and seismic and $19 million for facilities. The Trust drilled a total of 66 gross wells at its conventional plays in 2005.

Wilson Creek

PrimeWest continued its multi-zone development strategy at Wilson Creek in 2005, drilling eight operated and 30 non-operated gross wells targeting various formations including the Belly River, Glauconitic, Mannville, Rock Creek and Edmonton sands. Capital expenditures totalled $27.7 million, comprised of $19.0 million for drilling, completions, equipping and tie-in, $2.7 million for land and seismic and $6.0 million for facilities. Production averaged approximately 4,300 BOE/day in 2005.

Crossfield/Lone Pine Creek/Irricana

The 2004 Calpine acquisition increased PrimeWest's land base at Crossfield, making it the Trust's second-largest area. Capital expenditures at Crossfield in 2005 totalled $11.9 million, comprised of $7.8 million for drilling, completions, equipping and tie-in, $0.4 million for land and seismic and $3.7 million for facilities. PrimeWest drilled three Pekisko wells in 2005 in the Lone Pine Creek area. Four deeper drilling opportunities targeting the Leduc and Nisku are planned for completion in 2006. Crossfield is a very large, historical Wabamun and Pekisko formation natural gas pool with original-gas-in-place of more than 1 trillion cubic feet. Remaining resource potential of more than 100 bcf will be produced, in some instances, using long-life, horizontal wells. PrimeWest's production averaged approximately 4,000 BOE/day from these properties during 2005. More than 23,000 net acres of undeveloped land are available for future development opportunities.

We are planning an extensive, one-time turndown of our facility at Crossfield in September 2006 to facilitate major modifications required to enhance long-term plant efficiencies. The turndown will result in more than 3,500 BOE/day of production shut-in for an estimated four weeks, impacting full year volumes by approximately 300 BOE/day.

Valhalla and Laprise

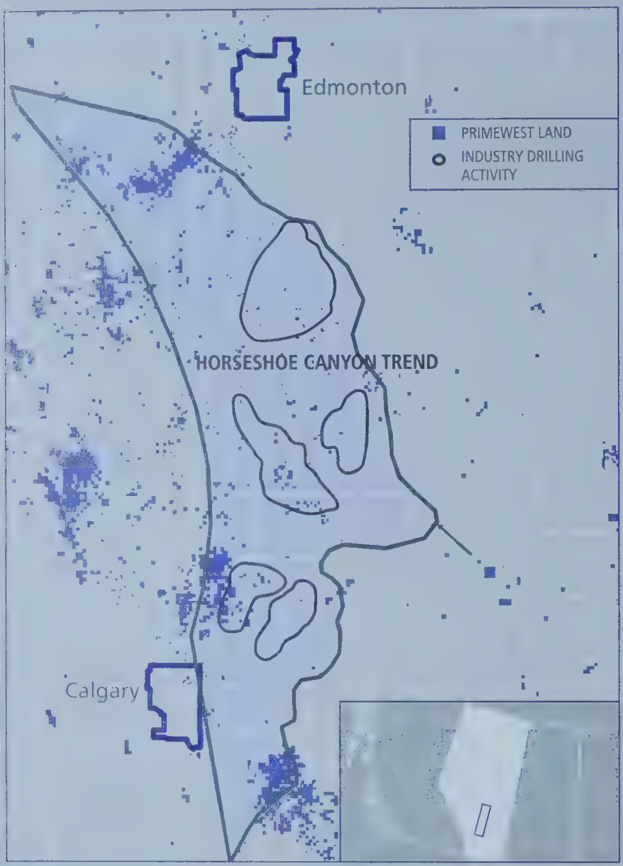
Valhalla offers the Trust low-risk downspacing and infill drilling opportunities in the Montney and Doig formations, with additional multi-zone natural gas targets in the Gething and Halfway formations. Infill drilling opportunities and field compression installations at Laprise are expected to provide the Trust with low-risk production and reserve additions in 2006.

Future Opportunities

With more than 250,000 net acres of undeveloped land, PrimeWest continues to develop its low-risk conventional development plays, leveraging off its network of existing oil and natural gas facility infrastructure.

The conventional development play represents predominantly heritage properties in PrimeWest's asset base. With over 250,000 net acres of undeveloped land, the Trust can leverage off its existing oil and natural gas infrastructure to continue developing these low-risk properties.

Coalbed Methane



Coalbed Methane

Alberta's provincial energy regulator estimates coalbed methane (CBM) resources consist of up to 500 trillion cubic feet of gas-in-place. To date, industry participants have drilled more than 5,000 CBM wells, the majority in the Horseshoe Canyon trend. The Horseshoe Canyon coals underlie much of the lands in central and southeast Alberta, where PrimeWest has large contiguous land holdings in three operated areas at Crossfield, Thorsby and Brant Farrow.

Quick Facts

PRIMARY COMMODITY:	Natural gas from coal or CBM
MAIN PROPERTIES:	Crossfield, Brant Farrow, Thorsby
YEAR-END 2005 RESERVES:	0.2 mmBOE Proved plus Probable
2005 CAPITAL INVESTED:	$3 million
2005 WELL RECOMPLETIONS:	11 gross wells
2006 DEVELOPMENT CAPITAL:	$5-10 million
2006 PLANNED DRILLING:	10-15 gross wells

PrimeWest began evaluating the potential of its CBM assets late in 2005 with the recompletion of several old wellbores to test the productivity of the local coals. Additional delineation drilling is planned for 2006 to further understand the potential of this resource. PrimeWest expects its CBM activity to yield production additions in 2007 and beyond.

Investing in Coalbed Methane

With close to 125,000 net acres of land on the developing Horseshoe Canyon CBM trend, PrimeWest is well positioned to take advantage of the emerging CBM resource play in Western Canada. PrimeWest is in the preliminary assessment stages of its CBM assets in three large, concentrated operated areas.

The Alberta Energy and Utilities Board (EUB), the main provincial energy regulator, estimates Alberta's CBM resources to be up to 500 trillion cubic feet of gas-in-place. Although nearly all of this resource is still at the high-risk early stage of exploration, the industry became much more active in 2005, primarily in the development of the coals in the Horseshoe Canyon trend, drilling more than 2,800 CBM wells. This brings the total number of CBM wells drilled to date to more than 5,000. Several competitors have drilled CBM wells within kilometres of PrimeWest's CBM-prospective lands. The drier Horseshoe Canyon coals underlie much of PrimeWest's CBM-prospective lands in central and southeast Alberta, consisting of large contiguous land holdings in three operated areas at Crossfield, Thorsby and Brant Farrow. All three properties have existing low pressure conventional gas plants and extensive field infrastructure that could be utilized to improve capital efficiencies as the CBM resources are developed.

PrimeWest began evaluating the potential of its CBM assets in 2005 with the recompletion of several existing older well bores to test the productivity potential of the thinly inter-bedded Horseshoe Canyon coals. The information gathered from these recompletions, coupled with the results of delineation drilling planned for 2006, are expected to provide critical information for PrimeWest to determine the longer-term development potential of its CBM assets. Commercial development of these CBM assets, including initial marketable production volumes, could start as early as 2007.

In 2005, approximately 2,800 wells were drilled in the Horseshoe Canyon trend by industry participants. With our large land holdings at Crossfield, Thorsby and Brant Farrow, we are evaluating the potential of our CBM assets, with possible development of these assets as early as 2007.

Environment, Health And Safety

PrimeWest is committed to maintaining high standards in Environment, Health and Safety performance.

In 2005, PrimeWest demonstrated its strong commitment to Environment, Health and Safety (EH&S) through the further development and implementation of its closed-loop audit and corrective action environment and safety compliance program. In 2005, PrimeWest obtained a Platinum ranking through the Canadian Association of Petroleum Producers' (CAPP) Environment, Health and Safety Stewardship Program. This is the highest rating. The program benchmarks EH&S performance against other producers in the oil and natural gas industry.

Environment

During the year, PrimeWest continued with the reclamation and remediation of nearly 600 locations. These locations are in various stages of cleanup and the Trust received reclamation certificates for a total of 36 locations. PrimeWest continues to manage all projects based on the risk that they pose to the environment and the public, as well as liability to the Trust. PrimeWest has developed an internal database program to assist with the management of reclamation, remediation and abandonment projects.

In 2005, the EUB implemented Directive 024, known as the Large Facility Program. Operators of all large sulphur plants were required to complete a liability assessment and include this total in the operator's Licensee Liability Rating. PrimeWest was required to include the calculated liability for the Crossfield Gas Plant and the former Lone Pine Creek Gas Plant. The overall Licensee Liability Rating for PrimeWest is 4.44, above the EUB's minimum threshold level of 1.0.

The Trust's EH&S group continues to work alongside the Business Development team to ensure that liabilities are reviewed and evaluated as part of due diligence in evaluating potential acquisitions. Training and education in all aspects of EH&S continues as part of the Safety Training Environmental Management (STEM) Program, which establishes EH&S performance expectations for field and Calgary-based staff.

Health and Safety

In 2004, PrimeWest received a Certificate of Recognition (COR) in Partnership and Safety from the Petroleum Industry Training Service (PITS). This certificate is endorsed by the Worker's Compensation Board in Alberta and British Columbia as proof that an operator is meeting a high safety standard. In October 2005, PrimeWest's Health and Safety Management System was audited again and was deemed to have met the standard required to maintain its' COR.

During the year, PrimeWest implemented a wide-ranging, in-house course of evaluation to train and test field operators in key health and safety competencies.

In an effort to maintain a state of preparedness to respond quickly and appropriately to any foreseeable type of emergency, during 2005 PrimeWest conducted a number of emergency response exercises in all areas of operation. In addition, corporate and operating area Emergency Response Plans (ERP's) have been streamlined and organizational changes made to strengthen corporate response capabilities.

PrimeWest continues to enhance the incident reporting and investigating process along with its compliance-based inspection system and operating standards. In the fourth quarter of 2005, a major project was initiated to integrate these functional areas with the existing Web-based preventative maintenance and asset management system under one electronic operating management system framework. This program will also provide statistical data and analysis to be used to identify trends and proactively develop controls to manage loss exposures.

MANAGEMENT'S DISCUSSION AND ANALYSIS

THE FOLLOWING IS MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A) AS AT FEBRUARY 23, 2006, OF PRIMEWEST ENERGY TRUST'S (REFERRED TO HEREINAFTER AS PRIMEWEST OR THE TRUST) OPERATING AND FINANCIAL RESULTS FOR THE YEAR ENDED DECEMBER 31, 2005, THE CORRESPONDING PERIOD IN THE PRIOR YEAR AS WELL AS INFORMATION AND OPINIONS CONCERNING THE TRUST'S OUTLOOK BASED ON CURRENTLY AVAILABLE INFORMATION. THIS DISCUSSION SHOULD BE READ IN CONJUNCTION WITH THE TRUST'S AUDITED CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2005 AND 2004, TOGETHER WITH ACCOMPANYING NOTES.

Financial ($ millions, except per BOE(1) and Per Trust Unit amounts)	2005	2004	Change (%)
Gross revenue, net of transportation expense	$ 749.7	$ 513.7	46
Per BOE	50.90	39.45	29
Cash flow from operations	414.1	266.8	55
Per BOE	28.11	20.49	37
Per Trust Unit – Basic (2)	5.46	4.49	22
Per Trust Unit – Diluted (3)	5.16	4.33	19
Royalty expense	172.8	119.8	44
Per BOE	11.73	9.20	28
Operating expense	117.0	88.9	32
Per BOE	7.94	6.83	16
Cash general and administrative expense	22.9	19.0	21
Per BOE	1.56	1.46	7
Non-cash general and administrative expense (4)	5.4	4.1	32
Per BOE	0.37	0.32	16
Interest expense (5)	28.3	20.6	37
Per BOE	1.92	1.58	22
Net income	207.5	105.4	97
Per Trust Unit – Basic (2)	2.73	1.77	54
Per Trust Unit – Diluted (3)	2.66	1.77	50
Distributions to Unitholders	276.6	196.1	41
Per Trust Unit (6)	3.66	3.30	11
Net debt (7)	323.7	552.0	(41)
Per Trust Unit (8)	3.97	7.77	(48)

(1) All calculations required to convert natural gas to a crude oil equivalent (BOE) have been made using a ratio of 6,000 cubic feet of natural gas to one barrel of crude oil. BOE's may be misleading, particularly if used in isolation. The BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

(2) The basic per Trust Unit calculation includes the weighted average Trust Units outstanding and Trust Units issuable upon exchange of the outstanding Exchangeable Shares of PrimeWest Energy Inc. (Exchangeable Shares).

(3) The diluted per Trust Unit calculation includes the weighted average Trust Units outstanding, Trust Units issuable upon exchange of the outstanding Exchangeable Shares, the deemed conversion of the Convertible Unsecured Subordinated Debentures (Debentures) and Trust Units issuable pursuant to the Long-Term Incentive Plan (LTIP). Interest expense incurred on the Debentures is added back to net income and to cash flow for the diluted per Trust Unit calculation.

(4) Non-cash general and administrative expense has been restated to reflect the change in method of accounting for its unit-based compensation. See note 3 to the Consolidated Financial Statements.

(5) Interest expense includes the interest on the Debentures.

(6) Based on Trust Units outstanding at the Record Date.

(7) Net debt is long-term debt including Debentures less working capital, excluding financial derivative assets and liabilities and current future income tax assets.

(8) The net debt per Trust Unit calculation includes outstanding Trust Units, Trust Units issuable upon exchange of the outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at the end of the period.

Daily Production Volumes	2005	2004	Change (%)
Daily sales volume			
Natural gas (mmcf/day)	178.2	145.1	23
Crude oil (bbls/day)	6,861	8,282	(17)
Natural gas liquids (bbls/day)	3,797	3,107	22
Total (BOE/day)	40,351	35,578	13

Realized Commodity Prices (Cdn$)	2005	2004	Change (%)
Natural gas ($/mcf) (1) (2)	8.43	6.61	28
Without hedging	8.75	6.70	31
Crude oil ($/bbl) (1)	49.05	36.83	33
Without hedging	58.48	44.46	32
Natural gas liquids ($/bbl)	55.92	43.69	28
Total ($/BOE) (1)	50.81	39.35	29
Without hedging	53.82	41.51	30

(1) Includes realized hedging losses.

(2) Excludes sulphur.

Forward-Looking Information

This annual report contains forward-looking or outlook information with respect to PrimeWest.

Certain statements contained in this annual report, and in certain documents incorporated by reference into this annual report, constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements.

We believe the expectations reflected in those forward-looking statements are reasonable. However, we cannot assure you that these expectations will prove to be correct. You should not unduly rely on forward-looking statements included in, or incorporated by reference into this annual report. These statements speak only as of the date of this annual report or as of the date specified in the documents incorporated by reference into this annual report, as the case may be.

In particular, this annual report, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- The quantity and recoverability of our reserves;
- The timing and amount of future production;
- Prices for oil, natural gas and natural gas liquids produced;
- Operating and other costs;
- Business strategies and plans of management;
- Supply and demand for oil and natural gas;
- Expectations regarding our ability to raise capital and to add to our reserves through acquisitions and exploration and development;
- Our treatment under governmental regulatory regimes;
- The focus of capital expenditures on development activity rather than exploration;
- The sale, farming in, farming out or development of certain exploration properties using third-party resources;
- The objective to achieve a predictable level of monthly cash distributions;
- The use of development activity and acquisitions to replace and add to reserves;
- The impact of changes in oil and natural gas prices on cash flow after hedging;
- Drilling plans;
- The existence, operations and strategy of the commodity price risk management program;
- The approximate and maximum amount of forward sales and hedging to be employed;
- Our acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- The impact of the Canadian federal and provincial governmental regulations on us relative to other oil and natural gas issuers of similar size;
- The goal to sustain or grow production and reserves through prudent management and acquisitions;

- The emergence of accretive growth opportunities; and
- Our ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets.

With respect to forward-looking statements contained in this annual report, including the documents incorporated herein by reference, we have made assumptions regarding, among other things:

- Future oil and natural gas prices and differentials between light, medium and heavy oil prices;
- The cost of expanding our property holdings;
- Our ability to obtain equipment in a timely manner to carry out development activities;
- Our ability to market our oil and natural gas successfully to current and new customers;
- The impact of increasing competition;
- Our ability to obtain financing on acceptable terms; and
- Our ability to add production and reserves through our development and exploitation activities.

Our actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and incorporated by reference into this annual report:

- Volatility in market prices for oil and natural gas;
- The impact of weather conditions on seasonal demand;
- Risks inherent in our oil and natural gas operations;
- Uncertainties associated with estimating reserves;
- Competition for, among other things: capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- Incorrect assessments of the value of acquisitions;
- Geological, technical, drilling and processing problems;
- General economic conditions in Canada, the United States and globally;
- Industry conditions, including fluctuations in the price of oil and natural gas;
- Royalties payable in respect of our oil and natural gas production;
- Government regulation of the oil and natural gas industry, including environmental regulation;
- Fluctuation in foreign exchange or interest rates;
- Unanticipated operating events that could reduce production or cause production to be shut-in or delayed;
- Failure to obtain industry partner and other third-party consents and approvals, when required;
- Stock market volatility and market valuations;
- OPEC's ability to control production and balance global supply and demand of crude oil at desired price levels;
- Political uncertainty, including the risks of hostilities, in the petroleum-producing regions of the world;
- The need to obtain required approvals from regulatory authorities; and
- The other factors discussed under Risk Factors contained this annual report.

These factors should not be construed as exhaustive. The forward-looking statements contained in this annual report and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We undertake no obligation to publicly update or revise any forward-looking statements.

PrimeWest does not endorse any of the analyst or consultant sourced material contained herein.

All figures reported in Canadian dollars unless otherwise stated.

Production figures stated are Company Interest before the deduction of royalties.

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer, Don Garner, and the Chief Financial Officer, Dennis Feuchuk, evaluated the effectiveness of PrimeWest's disclosure controls and procedures as of December 31, 2005, and concluded that PrimeWest's disclosure controls and procedures were effective to ensure that information PrimeWest is required to disclose:

- In its annual filings, interim filings or other reports (each as defined in National Instrument 52-109 of the Canadian Securities Administrators) filed or submitted by it under provincial securities legislation is recorded, processed, summarized and reported within the time periods specified in the provincial securities legislation and to ensure that information required to be disclosed by PrimeWest in its annual filings, interim filings or other reports filed or submitted under provincial securities legislation is accumulated and communicated to PrimeWest's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure; and
- In its annual filings, interim filings or other reports with the United States Securities and Exchange Commission (SEC) in the United States under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms, and to ensure that information required to be disclosed by PrimeWest in the reports that it files under the Exchange Act is accumulated and communicated to PrimeWest's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

The evaluation took into consideration PrimeWest's Communications and Disclosure Policy and the functioning of its executive officers, board of directors and board committees. In addition, the evaluation covered PrimeWest's processes, systems and capabilities relating to regulatory filings, public disclosures and the identification and communication of material information.

Changes to Internal Controls Over Financial Reporting

There were no changes to PrimeWest's internal control over financial reporting since September 30, 2005 that have materially affected, or are reasonably likely to materially affect PrimeWest's internal control over financial reporting.

Non-GAAP Measures

This annual report contains the following measurements that are not defined by Canadian Generally Accepted Accounting Principles (GAAP):

- Cash flow from operations on a total and per Trust Unit basis;
- Distributions per Trust Unit; and
- Net debt per Trust Unit.

These measurements do not have any standardized meaning prescribed by GAAP and are, therefore, unlikely to be comparable to similar measures presented by other entities.

Cash flow from operations is calculated from the Trust's cash flow statement as cash flow from operating activities before changes in working capital. Cash flow from operations per Trust Unit on a basic basis is calculated by dividing cash flow by the weighted average number of Trust Units outstanding plus Trust Units issuable upon the exchange of the outstanding Exchangeable Shares of PrimeWest Energy Inc. (Exchangeable Shares). Cash flow from operations per Trust Unit on a diluted basis is calculated using cash flow and adding back the interest expense on the Convertible Unsecured Subordinated Debentures (Debentures), divided by the diluted weighted average number of Trust Units outstanding in the period. The diluted weighted average number of Trust Units outstanding consists of the weighted average Trust Units plus Trust Units issuable upon the exchange of outstanding Exchangeable Shares and includes the Trust Units issuable pursuant to the conversion of the Debentures, and Trust Units issuable pursuant to PrimeWest's Long-Term Incentive Plan (LTIP). Cash flow from operations is a key performance indicator of PrimeWest's ability to generate cash and finance operations and pay monthly distributions.

Distributions per Trust Unit disclose the cash distributions accrued in 2005 based on the number of Trust Units outstanding on the Record Date.

Net debt per Trust Unit is calculated as long-term debt, including Debentures, less working capital, excluding financial derivative assets and liabilities and current future income tax assets divided by the number of Trust Units outstanding and Trust Units issuable upon the exchange of outstanding Exchangeable Shares and Trust Units issuable pursuant to the LTIP at December 31, 2005.

Business Strategy

PrimeWest Energy Trust is a conventional oil and natural gas royalty trust actively managed to generate monthly cash distributions for Unitholders. The Trust's operations are focused in Canada, with its assets concentrated in the Western Canada Sedimentary Basin. PrimeWest is one of North America's largest natural gas-weighted energy trusts.

Maximizing total return to Unitholders, in the form of cash distributions and appreciation in unit price, is PrimeWest's overriding objective. Our strategies for asset management and growth, financial management and corporate governance are outlined in this annual report along with a discussion of our performance in 2005 and our goals for 2006 and beyond.

We believe that PrimeWest can maximize total return to Unitholders by continuing to develop our core properties, making opportunistic acquisitions that emphasize value creation, exercising disciplined financial management which broadens access to capital while minimizing risk to Unitholders, and complying with strong corporate governance principles to protect the interests of all stakeholders.

Asset Management and Growth

PrimeWest has a strategy to focus expansion efforts on existing Canadian core areas and pursue depletion optimization strategies within those core areas to maximize asset value. We make every effort to obtain operatorship of our asset base and maintain high working interests in core areas. We currently maintain operatorship of 80% of our assets, which allows us to use existing infrastructure and synergies within our core areas. We believe this high level of control can translate into cost efficiencies and timing of capital outlays and projects. The current size of the Trust gives us the ability and critical mass to make acquisitions of significant size, while being able to add value by transacting smaller acquisitions.

Financial Management

PrimeWest strives to maintain a prudent debt position, to allow us to fund smaller acquisitions and to fund ongoing development activities without tapping the capital markets. Our long-term debt is comprised of bank credit facilities through a bank syndicate, U.S.-dollar-denominated Senior Secured Notes (Secured Notes) and the Debentures. Our diversified debt instruments help to reduce our reliance on the bank syndicate. PrimeWest's commodity hedging approach is intended to help to stabilize cash flow, reduce volatility and, when applicable protect near-term acquisition economics.

Since August 2003, PrimeWest has followed a strategy of maintaining a distribution payout ratio of approximately 70-90% of cash flow, calculated on an annual basis. The strength in commodity prices has increased the Trust's cash flow from operations available for distribution to Unitholders. The Board of Directors of PrimeWest will continue to consider a variety of factors in establishing the monthly distribution level. These factors include, but are not limited to: commodity price outlook, cash flow forecast, capital development plans, debt levels, tax considerations and competitive industry distribution practices.

The 2005 payout ratio was approximately 67% of annual operating cash flow. The retained cash flow was utilized to fund the Trust's capital spending program and repay debt. PrimeWest's net debt to cash flow ratio was 0.8 times at December 31, 2005 using 2005 annual cash flows.

PrimeWest's dual listing on the Toronto Stock Exchange (TSX) and New York Stock Exchange (NYSE) provides increased liquidity and a broadened investor base. The NYSE listing enables U.S. Unitholders to conveniently trade in our Trust Units, and allows us to access the U.S. capital markets in the future. Our status as a corporation for U.S. tax purposes simplifies tax reporting for our U.S. Unitholders.

For eligible Canadian and U.S. Unitholders, PrimeWest offers participation in the conventional Distribution Reinvestment Plan (DRIP), which represents a convenient way to maximize an investment in PrimeWest. Canadian residents may also participate in the Optional Trust Unit Purchase Plan (OTUPP) and the Premium Distribution Plan (PREP). For alternate investment requirements, PrimeWest also has Exchangeable Shares and Debentures available, which permit participation in PrimeWest without the ongoing tax implications associated with receiving a distribution.

Corporate Governance

PrimeWest remains committed to high standards of corporate governance and upholds the rules of the governing regulatory bodies under which it operates. Full disclosure of our compliance with existing corporate governance rules and regulations is contained in the Trust's Management Proxy Circular and is available on our website at www.primewestenergy.com. PrimeWest actively monitors the corporate governance and disclosure environment to ensure compliance with current and future requirements.

Our high standards of corporate governance are not limited to the boardroom. At the field level, PrimeWest proactively manages environmental, health and safety issues. We place a great deal of importance on community involvement and maintaining good relationships with landowners.

Financial and Operating Highlights

- Production in 2005 averaged 40,351 BOE/day, up by 13% from the 2004 level of 35,578 BOE/day, as a result of the Calpine acquisition in the third quarter of 2004 and development capital volume additions, partially offset by minor asset divestments transacted in December 2004 and natural production declines.
- Operating margin increased to $31.54/BOE for 2005, up by 25% from 2004 primarily due to higher commodity prices throughout the year, offset by the impact of the commodity hedging program as well as higher operating costs and royalties in 2005.
- Distributions of $3.66 per Trust Unit in 2005 compared to $3.30 per Trust Unit in 2004. The distribution level was increased in December 2005 by 20% from $0.30 per Trust Unit monthly to $0.36 per Trust Unit monthly. PrimeWest's payout ratio for 2005 was approximately 67% compared to the 2004 payout ratio of 74%. The 2005 lower payout ratio reflects the increases in cash flow due to increased commodity prices and retention of cash to fund development capital opportunities as well as reducing outstanding bank debt.
- Capital development program of $185.6 million added 14.7 mmBOE of Proved plus Probable reserves (including technical revisions) on a Company interest basis at an average of $12.63/BOE of reserves added, which excludes $4.22/BOE for future development capital. The capital development program replaced 100% of the 2005 production on a Proved plus Probable basis by reinvesting approximately 45% of cash flow from operations.
- PrimeWest's Reserve Life Index (RLI) at year-end 2005 is 11.0 years on a Company Interest Proved plus Probable basis. (Refer to the Disclosure of Oil and Natural Gas Reserves section later in this annual report for reserve definitions).
- Operating expenses were 32% higher in 2005 than in 2004, reflecting higher production volumes and higher industry-wide cost pressures. On a unit of production basis, operating expenses were 16% higher than in 2004 at $7.94/BOE versus $6.83/BOE.
- Cash general and administrative expense (G&A) increased $3.9 million over 2004 reflecting increases in labour costs, information technology expenses, office rent and property taxes associated with additional staffing and office space requirements resulting from the 2004 Calpine asset acquisition.
- Interest expense during 2005 was 37% higher than in 2004 due to a higher average net debt balance and higher interest rates during the year resulting from the issuance of the Debentures in the third quarter of 2004 to acquire the Calpine assets.
- The Distribution Reinvestment, Premium Distribution and Optional Trust Unit Purchase Plans contributed $55.7 million of equity capital to be reinvested in the capital development program and to repay debt.

Outlook 2006

PrimeWest expects 2006 production volumes to average approximately 38,000–39,000 BOE/day. Full-year operating costs are expected to be approximately $8.00/BOE. PrimeWest expects to invest approximately $275 million in its 2006 capital development program, with the focus primarily in the core areas of Caroline, Columbia, Wilson Creek, Crossfield and Brant Farrow.

Cash Flow Reconciliation

($ millions)	
2004 cash flow from operations	$ 266.8
Production volumes	67.3
Commodity prices	184.8
Net hedging change	(16.1)
Operating expense	(28.1)
Royalties	(53.0)
Interest expense	(7.7)
Other	0.1
2005 cash flow from operations	**$ 414.1**

The above table includes non-GAAP measurements (refer to discussion on non-GAAP measures on page 24).

The key performance driver for the Trust is cash flow from operations, which directly affects PrimeWest's ability to pay monthly distributions. Cash flow is generated through the production and sale of crude oil, natural gas and natural gas liquids, and is dependent on production levels, commodity prices, operating expenses, interest expenses, G&A expenses, hedging gains or losses, royalties and currency exchange rates. Some of these factors,

such as commodity prices, the currency exchange rate and royalties, are uncontrollable by PrimeWest. Factors that are, to a certain extent, controllable by PrimeWest are production levels and operating expenses, as well as interest and G&A expense.

Capital Spending

($ millions)		2005		2004
Land and lease acquisitions	$	17.6	$	8.3
Geological and geophysical		7.6		8.2
Drilling and completions		106.5		69.8
Equipping and tie-in		26.5		12.1
Compression and processing		9.1		4.7
Gas gathering		3.9		4.4
Production facilities		11.5		15.8
Capitalized G&A expense		2.9		1.8
Development capital	$	185.6	$	125.1
Corporate/property acquisitions		2.7		807.4
Dispositions		(20.6)		(99.5)
Head office equipment		4.2		4.6
Total	$	171.9	$	837.6

Capital expenditures, including development, acquisitions and divestments, totalled approximately $171.9 million in 2005, versus $837.6 million in 2004. PrimeWest's property acquisitions in 2004 included the Calpine oil and natural gas assets.

PrimeWest's 2005 capital development program totalled $185.6 million (2004 – $125.1 million). PrimeWest drilled 132 gross (62.8 net) wells with a success rate of 98.5%. The capital program focused on the core areas of Caroline, Columbia, Wilson Creek, Valhalla and Brant Farrow. The development program added 10.7 mmBOE of Company Interest Proved reserves and 14.7 mmBOE of Company Interest Proved plus Probable reserves, including technical revisions.

		2005		2004
Development Program				
Proved reserve additions (mmBOE) (1)		10.7		7.7
Average cost ($/BOE) (2)(3)	$	22.25	$	16.59
Proved plus Probable reserve additions (mmBOE) (1)		14.7		9.1
Average cost ($/BOE) (2)(3)	$	16.85	$	16.91
Acquisition Program (4)				
Proved reserve additions (mmBOE)		(0.5)		42.4
Average cost ($/BOE) (1) (4)	$	(35.8)	$	16.57
Proved plus Probable reserve additions (mmBOE)		(0.6)		53.2
Average cost ($/BOE) (1) (4)	$	(29.83)	$	13.20

(1) Proved and Proved plus Probable reserve additions in 2004 exclude the impact of economic factors.

(2) Under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, the implied methodology to be used to calculate finding, development and acquisition (FD&A) costs includes the change during the current year in estimated future development costs (FDC). The average cost per BOE from Company Interest Proved reserves additions includes the change in the current year FDC of $4.91/BOE ($0.35/BOE for 2004) and the average cost per BOE from Company Interest Proved plus Probable reserve additions, including the change in the current year FDC of $4.22/BOE ($3.17/BOE for 2004).

(3) The aggregate of the costs incurred under the capital development program in 2005 and the estimated FDC generally will not reflect total finding and development costs related to reserve additions for that year.

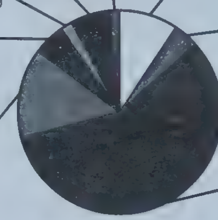
(4) Net of dispositions.

Investment in drilling, completions and tie-in represented 72% of development capital that contributed to new reserve additions in 2005. Investment in facilities totalled $24.5 million, representing 13% of development capital, on projects related to debottlenecking, increasing capacity or other activities that contribute to future production volumes.

In 2006, PrimeWest plans to invest approximately $275 million in its capital development programs.

Given that production volumes will decline naturally over time as oil or natural gas reservoirs are depleted, PrimeWest is continually striving to offset this natural decline, and add to reserves in an effort to sustain cash flows. Investment in activities such as development drilling, workovers and recompletions can add incremental production volumes and reserves.

Capital is allocated on the basis of anticipated rate of return on projects undertaken. At PrimeWest, every capital project is measured against economic evaluation criteria prior to approval. These criteria include expected return, risks and further development opportunities.



2005 Development Capital

Assets

Since inception, PrimeWest has focused on the conventional oil and natural gas plays of the Western Canada Sedimentary Basin. Within this focused area, we have a diversified suite of assets producing from multiple geological zones and stretching from northeast B.C. across much of Alberta. We believe this diversity reduces risks to overall corporate production and cash flow, while the core area focus allows us to capitalize on our existing technical knowledge in each of the major properties.

Reserves and Production

Company Interest Reserves – Forecast Prices and Costs

The following table sets forth a reconciliation of light, medium and heavy crude oil, natural gas, natural gas liquids and total BOE of the Company Interest reserves of PrimeWest for the year ended December 31, 2005. The table is derived from the January 23, 2006 report (the GLJ Report) of the independent reserve evaluators, GLJ Petroleum Consultants Ltd. (GLJ), using forecast price and cost estimates, and reconciled to December 31, 2004. PrimeWest's Company Interest reserves include working interest and royalty reserves receivable. This definition is consistent with the basis on which reserves were reported in prior years. See further discussion of reserves definitions and National Instrument 51-101 (NI 51-101) under Disclosure of Oil and Gas Reserves – Standards of Disclosure for Oil and Gas Activities below.

Forecast prices are based on the consultants' average price projections from GLJ, Sproule Associates Limited and McDaniel & Associates Consultants Ltd., all of which are effective January 1, 2006.

	Light, Medium and Heavy Crude Oil (mbbls)				Natural Gas (bcf)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
Dec. 31, 2004	19,052	19,765	4,138	23,903	450.2	529.2	148.7	677.9
Capital Additions [1]	303	399	620	1,019	17.9	23.9	19.8	43.7
Improved Recovery [2]	474	501	189	690	10.6	23.7	2.0	25.7
Technical Revisions	806	760	(149)	611	10.1	1.3	(3.5)	(2.2)
Acquisitions	0	0	0	0	0.2	0.2	0	0.2
Dispositions	(57)	(57)	(15)	(72)	(2.6)	(2.6)	(0.4)	(3.0)
Economic Factors	0	0	0	0	0	0	0	0
Production	(2,504)	(2,504)	0	(2,504)	(65.0)	(65.0)	0	(65.0)
Dec. 31, 2005	18,073	18,864	4,783	23,646	421.4	510.7	166.6	677.3

Columns may not add due to rounding

	Natural Gas Liquids (mbbls)				Total (mmBOE)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
Dec. 31, 2004	11,739	13,988	4,282	18,270	105.8	121.9	33.3	155.2
Capital Additions (1)	462	675	564	1,239	3.7	5.1	4.4	9.5
Improved Recovery (2)	327	741	59	801	2.6	5.2	0.6	5.8
Technical Revisions	(243)	(549)	(267)	(816)	2.2	0.4	(1.0)	(0.6)
Acquisitions	0	0	0	0	0	0	0	0
Dispositions	(36)	(36)	(4)	(40)	(0.5)	(0.5)	(0.1)	(0.6)
Economic Factors	0	0	0	0	0	0	0	0
Production	(1,386)	(1,386)	0	(1,386)	(14.7)	(14.7)	0	(14.7)
Dec. 31, 2005	**10,864**	**13,434**	**4,634**	**18,068**	**99.2**	**117.4**	**37.2**	**154.6**

Columns may not add due to rounding.

(1) Capital additions include exploration discoveries and drilling extensions.

(2) Improved recovery includes infill drilling and improved recovery.

Net Reserves – Forecast Prices and Costs

The following table sets forth a reconciliation of PrimeWest's Net Reserves for the year ended December 31, 2005 derived from the GLJ Report using forecast price and cost estimates. These year-end reserves are reconciled to December 31, 2004 reserves. PrimeWest's Net Reserves include working interest reserves plus royalties receivable less royalties payable, as stipulated by NI 51-101. All data in the following tables was provided by GLJ.

	Light and Medium Crude Oil (mbbls)				Heavy Oil (mbbls)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
Dec. 31, 2004	14,767	15,296	3,098	18,394	2,541	2,623	503	3,126
Capital Additions (1)	178	251	321	572	85	85	178	263
Improved Recovery (2)	369	389	146	535	41	49	18	68
Technical Revisions	268	261	(26)	235	104	92	(103)	(11)
Discoveries	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0
Dispositions	(48)	(48)	(12)	(60)	0	0	0	0
Economic Factors	137	133	17	150	149	151	34	185
Production	(1,573)	(1,573)	0	(1,573)	(564)	(564)	0	(564)
Dec. 31, 2005	**14,098**	**14,709**	**3,544**	**18,253**	**2,355**	**2,436**	**630**	**3,066**

Columns may not add due to rounding.

	Associated and Non-Associated Gas (bcf)				Natural Gas Liquids (mbbls)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
Dec. 31, 2004	358.2	420.4	117.6	538.0	8,308	9,911	3,008	12,919
Capital Additions (1)	14.0	17.9	14.6	32.6	306	416	374	790
Improved Recovery (2)	8.2	18.5	1.4	19.9	219	528	36	563
Technical Revisions	5.8	(0.2)	(2.4)	(2.7)	(152)	(381)	(196)	(577)
Discoveries	0.1	0.9	0.3	1.2	0	45	18	63
Acquisitions	0.1	0.1	0.0	0.2	0	0	0	0
Dispositions	(1.9)	(1.9)	(0.3)	(2.2)	(24)	(24)	(3)	(27)
Economic Factors	1.3	1.1	0.4	1.5	(12)	(22)	(3)	(25)
Production	(49.5)	(49.5)	0	(49.5)	(977)	(977)	0	(977)
Dec. 31, 2005	**336.4**	**407.2**	**131.7**	**539.0**	**7,668**	**9,495**	**3,234**	**12,729**

Columns may not add due to rounding.

	Natural Gas from Coal (mmcf)				Total (mmBOE)			
	Proved Producing	Total Proved	Probable	Proved plus Probable	Proved Producing	Total Proved	Probable	Proved plus Probable
Dec. 31, 2004	0	0	0	0	85.3	97.9	26.2	124.1
Capital Additions (1)	0	226	395	621	2.9	3.8	3.4	7.2
Improved Recovery (2)	177	386	113	499	2.0	4.1	0.5	4.6
Technical Revisions	37	38	11	48	1.2	(0.1)	(0.7)	(0.8)
Discoveries	0	0	0	0	0.0	0.2	0.1	0.3
Acquisitions	0	0	0	0	0.0	0.0	0.0	0.0
Dispositions	0	0	0	0	(0.4)	(0.4)	(0.1)	(0.5)
Economic Factors	0	0	0	0	0.5	0.4	0.1	0.6
Production	(44)	(44)	0	(44)	(11.4)	(11.4)	0.0	(11.4)
Dec. 31, 2005	**171**	**606**	**518**	**1,124**	**80.2**	**94.6**	**29.5**	**124.1**

Columns may not add due to rounding.

(1) Capital additions include exploration discoveries and drilling extensions.

(2) Improved recovery includes infill drilling and improved recovery.

Reserves and Future Net Revenues

The following tables provide reserves data and a breakdown of reserves on a Company Interest, Gross and Net basis and the net present value of future net revenues using consultant's average pricing.

	Reserves					
	Light And Medium Crude Oil (mbbls)			Heavy Oil (mbbls)		
Reserves Category	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	15,512	13,959	14,098	2,561	2,550	2,355
Developed Non-Producing	351	351	304	90	90	81
Undeveloped	350	331	307	0	0	0
Total Proved	16,212	14,641	14,709	2,652	2,640	2,436
Probable	4,085	3,777	3,545	697	696	630
Total Proved plus Probable	**20,297**	**18,417**	**18,253**	**3,349**	**3,335**	**3,066**

Columns may not add due to rounding.

	Reserves					
	Natural Gas (bcf)			Natural Gas Liquids (mbbls)		
Reserves Category	Company Interest	Gross	Net	Company Interest	Gross	Net
Proved						
Developed Producing	421.4	411.8	336.6	10,864	10,635	7,668
Developed Non-Producing	36.9	36.8	29.4	1,128	1,125	820
Undeveloped	52.5	52.5	41.9	1,442	1,442	1,008
Total Proved	510.7	501.1	407.8	13,434	13,203	9,495
Probable	166.6	164.5	132.3	4,634	4,583	3,233
Total Proved plus Probable	**677.3**	**665.6**	**540.1**	**18,068**	**17,786**	**12,729**

Columns may not add due to rounding.

Reserves Category	Total (mBOE) Company Interest	Gross	Net
Proved			
Developed Producing	99,162	95,778	80,214
Developed Non-Producing	7,724	7,697	6,106
Undeveloped	10,535	10,517	8,292
Total Proved	117,422	113,993	94,612
Probable	37,181	36,474	29,450
Total Proved plus Probable	**154,603**	**150,466**	**124,062**

Columns may not add due to rounding.

	Net Present Values of Future Net Revenue ($ millions) Before Future Income Tax Expenses Discounted at (%)					After Future Income Tax Expenses Discounted at (%)				
Reserves Category	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Proved										
Developed Producing	3,241.2	2,387.1	1,935.7	1,656.2	1,464.1	3,241.2	2,387.1	1,935.7	1,656.2	1,464.1
Developed Non-Producing	265.0	178.6	140.3	118.2	103.5	265.0	178.6	140.3	118.2	103.5
Undeveloped	277.7	179.8	128.9	97.9	76.9	277.7	179.8	128.9	97.9	76.9
Total Proved	3,783.8	2,745.5	2,204.9	1,872.3	1,644.6	3,783.8	2,745.5	2,204.9	1,872.3	1,644.7
Probable	1,259.7	701.0	479.0	365.0	295.7	1,259.7	701.0	479.0	365.0	295.7
Total Proved plus Probable	**5,043.6**	**3,446.6**	**2,684.0**	**2,237.2**	**1,940.4**	**5,043.6**	**3,446.6**	**2,684.0**	**2,237.2**	**1,940.4**

Columns may not add due to rounding .

Daily Production Volumes

	2005	2004	Change (%)
Natural gas (mmcf/day)	**178.2**	145.1	23
Crude oil (bbls/day)	**6,861**	8,282	(17)
Natural gas liquids (bbls/day)	**3,797**	3,107	22
Total (BOE/day)	**40,351**	35,578	13
Gross overriding royalty volumes included above (BOE/day)	**1,338**	1,440	(7)

All production information is reported before the deduction of Crown and freehold royalties.

The 13% increase in daily average production year-over-year is due in part to the acquisition of the Calpine assets in the third quarter of 2004, combined with production additions from 2005 development activity, offset partially by the asset divestment in December 2004 and the natural decline of production. Based on 2005 production statistics, natural production decline is estimated at approximately 17%. During 2005, approximately 2,900 BOE/day of annualized incremental production was brought on-stream from development activities to help offset natural decline. Approximately 2,200 BOE/day of new production remained "behind pipe", or awaiting tie-in to production facilities, at the end of 2005.

PrimeWest expects production for full-year 2006 to be 38,000–39,000 BOE/day. This estimate incorporates PrimeWest's expected natural decline rate, production volume shut-ins due to scheduled plant turnarounds at Crossfield, Caroline and Edson (estimated to affect approximately 600 BOE/day on a full-year average basis), the reinstatement effective January 1, 2006 of the Maximum Rate Limitation (MRL) on wells in the Cecil area and others, all offset by production additions from the 2006 capital development program.

Commodity Prices

Average Benchmark Prices	2005	2004	Change (%)
Natural Gas			
NYMEX (US$/mcf)	$ 8.55	$ 6.09	40
AECO (Cdn$/mcf)	$ 8.48	$ 6.79	25
Crude oil – W.T.I. (US$/bbl)	$ 56.56	$ 41.40	37

Average Realized Sales Prices (1) (Cdn$)	2005	2004	Change (%)
Natural gas ($/mcf) (2)	$ 8.43	$ 6.61	28
Crude oil ($/bbl)	$ 49.05	$ 36.83	33
Natural gas liquids ($/bbl)	$ 55.92	$ 43.69	28
Total ($/BOE)	$ 50.81	$ 39.35	29
Realized hedging loss included in prices above ($/BOE)	$ (3.01)	$ (2.16)	(39)

(1) Includes realized hedging losses.

(2) Excludes sulphur.

The selling price that PrimeWest realized from its 2005 production, net of hedging impact, was 29% higher than in 2004. The commodity hedging program resulted in a reduction of PrimeWest's 2005 average realized price by $3.01/BOE, compared to a reduction of $2.16/BOE in 2004. This hedging impact reflects the amount of additional revenue foregone by PrimeWest as a result of its hedging program, through which the price of a portion of its production was capped at certain price levels in exchange for downward price protection. PrimeWest utilizes financial hedges as part of its financial strategy to reduce the impact of commodity price volatility and to improve the predictability of cash flow from operations.

The Canadian and U.S. currency exchange rate is another factor that has an impact on the price PrimeWest realizes from its production. Since Canadian prices of oil and natural gas are influenced by benchmark prices that are set in U.S. dollars, a stronger Canadian dollar will translate into lower realized prices and revenues when expressed in Canadian dollars. During 2005, the Canadian dollar exchange rate increased by approximately 3% versus the U.S. dollar, from US$0.831 at December 31, 2004 to US$0.858 at December 31, 2005. The stronger Canadian dollar during 2005 negatively impacted PrimeWest's Canadian realized prices and revenue receipts.

Crude Oil Prices

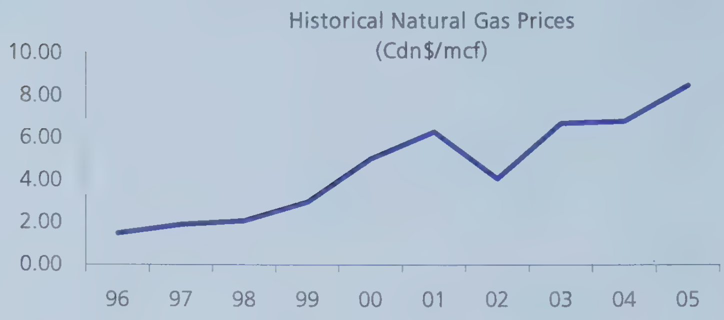
Continued growth in global oil demand combined with supply concerns resulted in strong crude oil prices in 2005. On the demand side, robust economic growth in Asia, notably in China and India, together with a strong consumer economy in the U.S. have increased worldwide oil consumption. Supply disruptions occurred in various parts of the world, due to political uncertainty and natural disasters, such as hurricanes Katrina and Rita, which shut down a large volume of production in the Gulf of Mexico. Within OPEC, the excess production capacity that once existed among most members was reduced by the increased demand. In 2005 Saudi Arabia, Kuwait and the United Arab Emirates were the only OPEC member countries with meaningful spare capacity that could be used to offset supply disruptions. As a result, oil prices fluctuated throughout 2005 in response to world events and weather conditions. During 2005, oil went from US$43.45/bbl at the beginning of the year to a historical high of US$69.81/bbl on August 30, 2005, before dropping to US$61.04/bbl by year-end.

The forward price of crude oil as at December 31, 2005 indicated a rising trend over the next 12 months to approximately US$64.00/bbl by 2006 year-end. Key factors that are expected to influence prices in 2006 include: potential slowdown in worldwide demand growth, particularly in China and India, as a response to higher prices; attempts by OPEC to influence prices by adjusting production quotas; the ability of Iraq to restore more of its oil export capability and the rate and magnitude of production growth from OPEC and non-OPEC producers.

The netbacks for Canadian companies and energy trusts that produce a heavier grade of crude oil were negatively affected by a wide price differential versus lighter, sweet crude in 2005. As the majority of crude production coming into the markets worldwide was of heavier and more sour quality, the discount versus lighter oil remained at a high level throughout 2005, as heavy-oil refining capacity was reaching full utilization. In addition, the realized price for heavy oil producers was negatively affected by an increase in the price of condensate, a natural gas by-product that is widely used as a diluent to blend heavier crude oil for pipeline transport.

Approximately 32% of PrimeWest's crude oil production is made up of medium to slightly heavy grades. These products do not require any diluent blending and attract a better pricing differential than heavier crude oil production.

Natural Gas Prices



PrimeWest's average realized natural gas price in 2005 increased by 28% to $8.43/mcf from a 2004 average of $6.61/mcf. At the beginning of 2005, the outlook for natural gas prices was markedly bearish due to mild winter weather and a decline in heating demand. The natural gas storage level at the end of the 2005 winter season was higher than at the end of the 2004 winter season, which had also experienced a warmer than normal winter. Over the ensuing summer, this year-on-year storage overhang was gradually worked off by the increased natural gas demands in response to hotter temperatures. The impact of Hurricanes Katrina and Rita turned a surplus storage position into deficit, causing a run-up of natural gas prices to approximately US$15.00/mmbtu by early December. Prices began to soften in the latter part of December due to unseasonably warm weather. At 2005 year-end, North American natural gas storage levels were approaching the five-year average. Forward natural gas prices as of December 31, 2005 reflected a bullish trend, but have softened with the warm weather in early 2006.

Key factors expected to influence prices in 2006 include: the speed of the restoration of shut-in Gulf of Mexico production; North American weather patterns during the upcoming summer and winter seasons; the ability of producers in Canada and the U.S. to replace and add to production levels through increased drilling; the continued growth of natural gas demand in the electricity sector; and the impact of government regulations and conservation efforts in response to higher natural gas prices.

Sales Revenue

Revenue ($ millions)[1]		2005	% of Total		2004	% of Total	Change (%)
Natural gas [2]	$	548.0	73	$	351.0	69	56
Crude oil		122.8	16		111.7	22	10
Natural gas liquids		77.5	11		49.7	9	56
Total	$	748.3		$	512.4		
Hedging loss included above	$	(44.3)		$	(28.2)		

(1) Net of transportation expense.

(2) Excludes sulphur.

PrimeWest's revenues from the sale of commodities for 2005 were $748.3 million compared to $512.4 million in the previous year, including the effect of hedging. Higher commodity prices along with increases in natural gas sales volumes were the major contributors to the increased revenue in 2005.

If the pricing environment softens in 2006, and the Canadian dollar remains strong, oil and natural gas revenues will be negatively impacted. Since approximately 73% of PrimeWest's revenues are derived from natural gas, the Trust has greater sensitivity to changes in natural gas prices than crude oil prices.

2005 Hedging Results

As part of our financial management strategy, PrimeWest uses a consistent commodity hedging approach. The purposes of the hedging program are to reduce volatility in cash flows, to protect acquisition economics against the unpredictable commodity price environment and to protect our capital structure when commodity prices cycle downwards, while at the same time retaining exposure to pricing upside. PrimeWest's hedging policy reflects a willingness to forfeit a portion of the pricing upside in return for protection against a significant downturn in prices.

	Crude Oil ($/bbl)				Natural Gas ($/mcf)				BOE ($/BOE)			
		2005		2004		2005		2004		2005		2004
Unhedged price	$	58.48	$	44.46	$	8.75	$	6.70	$	53.82	$	41.51
Hedging loss		(9.43)		(7.63)		(0.32)		(0.09)		(3.01)		(2.16)
Realized price	$	49.05	$	36.83	$	8.43	$	6.61	$	50.81	$	39.35

	2005 Hedging Loss		2004 Hedging Loss	
	% Hedged	$ millions	% Hedged	$ millions
Crude oil	60	$ 23.6	58	$ 23.1
Natural gas	55	20.7	54	5.1
Total		$ 44.3		$ 28.2

The table below shows the production volumes hedged at December 31, 2005.

2006	Q1	Q2	Q3	Q4	Full Year
Crude oil (bbls/day)	4,000	3,000	2,000	2,000	2,750
Natural gas (mmcf/day)	79	42	42	42	51
2007					
Crude oil (bbls/day)	500	500	0	0	250
Natural gas (mmcf/day)	14	0	0	0	4

A summary of hedging contracts in place as at December 31, 2005 is available under note 17 to the Consolidated Financial Statements.

PrimeWest's derivatives are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period.

The 2005 income statement includes an unrealized loss of $11.6 million on derivatives resulting from the change in the mark-to-market valuation of the derivative financial instruments during the period. The loss was comprised of a $6.6 million gain for crude oil hedges, an $18.3 million loss for natural gas hedges and a $0.1 million gain for electrical power hedges.

For the year ended December 31, 2005 the cash impact of contract settlements was a $43.5 million loss, comprised of a $23.6 million loss in crude oil, a $20.7 million loss in natural gas, and a $0.8 million gain on electrical power.

Royalties

Royalties are paid by PrimeWest to the owners of mineral rights with whom PrimeWest holds leases. PrimeWest has mineral leases with the Crown (provincial and federal governments) and freeholders (individuals or other companies).

($ millions, except per BOE)	2005	2004	Change (%)
Royalty expense	$ 172.8	$ 119.8	44
Per BOE	$ 11.73	$ 9.20	28
Royalties as a percentage of sales revenues			
With hedge revenue	23%	23%	
Excluding hedge revenue	22%	22%	

Royalty expenses as a percentage of sales have remained constant when compared to the previous year.

The Crown royalty system is based on a sliding scale structure that increases the royalty rates as commodity prices rise until a maximum rate is achieved. Because of the sliding scale Crown royalty system, future changes to commodity prices will result in changes to royalty rates and expenses.

Operating Expenses

($ millions, except per BOE)	2005	2004	Change (%)
Operating expense	$ 117.0	$ 88.9	32
Per BOE	$ 7.94	$ 6.83	16

Operating expenses for 2005 increased by $28.1 million or 32% over 2004 mainly due to the increase in volumes resulting from the Calpine asset acquisition, which occurred in the third quarter of 2004.

The increase in operating costs per BOE is due mainly to the effects of inflationary pressures on the price of industry-related goods and services, due to the increased demand resulting from the current commodity price environment. Operating issues at the Valhalla plant and Boundary Lake pipeline repairs and clean-up costs also contributed to the increase in operating costs per BOE.

Operating Margin

($/BOE)	2005	2004	Change (%)
Sales price and other revenue[1]	$ 51.70	$ 40.13	29
Transportation expense	(0.49)	(0.63)	(22)
Royalties	(11.73)	(9.20)	28
Operating expense	(7.94)	(6.83)	16
Operating margin	$ 31.54	$ 23.47	34

(1) Includes hedging and sulphur.

Operating margins increased by 34% from 2004 on a per BOE basis. The increase in 2005 from 2004 is primarily due to higher sales prices, offset by higher per unit operating expenses and higher royalties. Operating margin measures the level of cash flow per BOE at the field level and before head office expenses.

G&A Expense

($ millions, except per BOE)	2005	2004 restated	Change (%)
Cash G&A expense	$ 22.9	$ 19.0	21
Per BOE	1.56	1.46	7
Non-cash G&A expense	5.4	4.1	32
Per BOE	$ 0.37	$ 0.32	16

Cash G&A expense increased by 21% in 2005 from 2004, primarily due to higher staff levels resulting in increased employee costs, office rent, property taxes and information technology expenditures. These increases are primarily attributable to the Calpine asset acquisition, which occurred in the third quarter of 2004. The increases were partially offset by overhead recoveries resulting from increases to capital expenditures and operating expenses.

Included in non-cash G&A expense is $3.6 million relating to the Unit Appreciation Rights (UARs), granted under the LTIP. UARs in the Trust are similar to stock options in a corporation. The program rewards employees based on total Unitholder return, which is comprised of cumulative distributions on a reinvested basis plus growth in Unit price. No benefit accrues to the UARs until the Unitholders have first achieved a 5% total annual return from the time of grant. PrimeWest continues to pay for the exercise of UARs in Trust Units. Also included in non-cash G&A expense is $1.8 million related to the Special Employee Retention Plan (SERP). See note 18 to the Consolidated Financial Statements.

Interest Expense

($ millions, except per Trust Unit)	2005	2004	Change (%)
Interest expense	$ 28.3	$ 20.6	37
Period end net debt level	$ 323.7	$ 552.0	(41)
Debt per Trust Unit	$ 3.97	$ 7.77	(48)
Average cost of debt	5.2%	4.8%	

Interest expense, representing interest on bank debt, the Secured Notes and the Debentures, increased to $28.3 million in 2005 from $20.6 million in 2004 due to higher average debt balances in 2005 compared to 2004, mainly resulting from the issuance of the Debentures to finance the Calpine acquisition. The Debentures also increased the average cost of debt with interest rates of 7.50% and 7.75% for the Series I and Series II Debentures, respectively.

Net debt at December 31, 2005 was 41% lower than at December 31, 2004 due to the repayment of $111.0 million of the bank credit facility and to the conversion of $186.2 million (net of accretion expense of $1.0 million) of Debentures into Trust Units.

Foreign Exchange Gain

The foreign exchange gain of $4.6 million resulted mainly from the translation of the U.S. dollar-denominated Secured Notes and related interest payable into Canadian dollars.

Depletion, Depreciation and Amortization (DD&A)

($ millions, except per BOE amounts)	2005	2004	Change (%)
Depletion, depreciation and amortization	$ 230.2	$ 197.3	17
Per BOE	$ 15.63	$ 15.15	3

The 2005 DD&A rate of $15.63/BOE is higher than the 2004 rate of $15.15/BOE mainly due to the impact of the Calpine asset acquisition.

Gain on Sale of Marketable Securities

PrimeWest sold its 8% ownership in the Viking Energy Royalty Trust (formerly Calpine Natural Gas Trust Units) in 2005 for net proceeds of $94.5 million, resulting in a gain of $27.1 million.

Site Reclamation and Restoration Reserve

Since the inception of the Trust, PrimeWest has maintained a site reclamation fund to pay for future costs related to well abandonment and site cleanup. The fund is used to pay for such costs as they are incurred. The reclamation and abandonment costs incurred in 2005 were $8.7 million, compared to $4.6 million in 2004.

The 2005 contribution rate for the fund was unchanged from 2004 at $0.50/BOE, which is expected to be sufficient to meet expenditure requirements for the future. As at December 31, 2005, the site reclamation fund had a balance of $9.2 million.

Net Asset Value

Net asset value (NAV) measures the net worth of PrimeWest by subtracting the value of debt from the estimated economic value of its underlying assets – primarily crude oil, natural gas and natural gas liquids reserves. The value placed on these reserves is the pre-tax present value of future net cash flows, discounted at 10%, as independently assessed by GLJ as at January 1, 2006. The present value of reserves reflects provisions for royalties, operating costs, future capital costs and site reclamation and abandonment costs, but is prior to deductions for income taxes, interest expense and G&A expense.

This calculation is a "snapshot" in time and is heavily dependent upon future commodity price expectations when the "snapshot" is taken. Accordingly, the NAV as at January 1, 2006 may not reflect fairly the equity market trading value of PrimeWest. It is also significant to note that NAV declines as reserves are produced and net operating cash flow is distributed to Unitholders. Value is delivered to Unitholders through such monthly distributions.

As at December 31 ($ millions, except per Trust Unit amounts)	2005 Consultants' Average	2004 Consultants' Average
ASSETS		
Present value of future net cash flow discounted at 10% [1][3]	$ 2,684.0	$ 1,714.4
Market value of Viking Energy Royalty Trust Units	-	91.0
Mark-to-market value of hedging contracts	(11.5)	0.1
Fair value of unproved lands	151.3	103.9
Reclamation fund	9.2	10.3
	$ 2,833.0	$ 1,919.7
LIABILITIES		
Debt and working capital surplus [2]	(267.9)	(378.5)
Net asset value	$ 2,565.1	$ 1,541.2
Outstanding Trust Units – millions, diluted	83.7	80.5
Net asset value per Trust Unit	$ 30.64	$ 19.15

(1) Company Interest Proved plus Probable reserves.

(2) Debt excludes Debentures.

(3) Refer to Summary of Oil and Natural Gas Reserves and Net Present Values of Future Net Revenues table under the section Disclosure of Oil and Natural Gas Reserves on page 45.

Price Assumptions	2005 Consultants' Average	2004 Consultants' Average
Edmonton Par Oil – Cdn$/bbl		
2005	$ -	$ 50.37
2006	$ 67.64	$ 47.46
2007	$ 66.40	$ 43.88
2008	$ 60.89	$ 40.89
2009	$ 56.83	$ 39.20
2010	$ 54.25	$ -
Spot Gas at AECO-C – Cdn$/mcf		
2005	$ -	$ 6.79
2006	$ 10.93	$ 6.52
2007	$ 9.88	$ 6.25
2008	$ 8.48	$ 5.95
2009	$ 7.59	$ 5.79
2010	$ 7.23	$ -

The NAV calculation is based on the above reference prices as of December 31, 2005 and 2004 and is highly sensitive to changes in price forecasts over time as well as in the exchange rate. In addition, the year-over-year change is impacted by the cash distributions made throughout the year, which totalled $276.6 million or $3.66 per Trust Unit in 2005. Also, the NAV calculation assumes a "blow down" scenario whereby existing reserves are produced without being replaced by acquisitions and development. A major cornerstone of PrimeWest's strategy is to replace reserves through accretive acquisitions and capital development.

Income and Capital Taxes

($ millions)	2005	2004 restated	Change (%)
Income and capital taxes	$ 2.8	$ 3.3	(15)
Future income tax recovery	(14.8)	(34.3)	(57)
Total	$ (12.0)	$ (31.0)	(61)

The decrease in the future income tax recovery is due to the increase in net income resulting primarily from higher oil and natural gas revenues.

Net Income

($ millions)	2005	2004 restated	Change (%)
Net income	$ 207.5	$ 105.4	97

Cash flow from operations, as opposed to net income, is the primary measure of performance for an energy trust. The generation of cash flow is critical to the ability of an energy trust to continue to sustain the monthly distribution of cash to Unitholders.

Conversely, net income is an accounting measure impacted by both cash and non-cash items. The largest non-cash items impacting PrimeWest's net income are the unrealized gains or losses on derivatives, foreign exchange gains or losses, DD&A and future income taxes.

Net income of $207.5 million in 2005 was higher than 2004 net income of $105.4 million primarily due to the increase in net oil and natural gas revenues resulting from increases to commodity prices and production volumes. Increases to operating expenses, DD&A, the unrealized loss on derivatives and lower future income tax recovery had a negative impact on net income.

Liquidity and Capital Resources

($ millions)	2005	2004	Change (%)
Long-term debt	$ 354.2	$ 656.3	(46)
Working capital surplus (1)	(30.5)	(104.3)	(71)
Net debt	323.7	552.0	(41)
Market value of Trust Units and Exchangeable Shares outstanding (2)	2,884.7	1,877.7	54
Total capitalization	$ 3,208.4	$ 2,429.7	32
Net debt as a % of total capitalization	**10%**	23%	

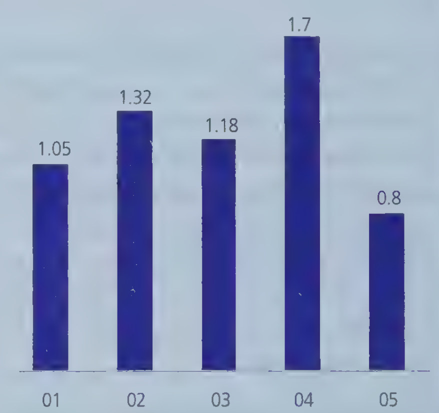
(1) Working capital surplus excludes financial derivative assets and liabilities and current future income tax assets.

(2) Based on December 31, 2005 Trust Unit closing price of $35.90 and exchangeable share ratio of 0.56399:1.

Long-term debt is comprised of bank credit facilities, Secured Notes and Debentures of $153.0 million, $145.4 million and $55.8 million, respectively.

PrimeWest had a borrowing base of $650 million at December 31, 2005. The bank credit facilities consist of an available revolving term loan of $458.7 million and an operating facility of $35 million, with the balance being attributed to the Secured Notes valued at $156.3 million based on the agreed U.S. dollar exchange rate at the time of last renewal. In addition to the amounts outstanding under the bank credit facility, PrimeWest has outstanding letters of credit in the amount of $6.6 million (2004 – $4.9 million). The credit facility revolves until June 30, 2006, by which time the lenders will have conducted their annual borrowing base review.

The Secured Notes in the amount of US$125 million have a final maturity date of May 7, 2010, and bear interest at 4.19% per annum, with interest paid semi-annually on November 7 and May 7 of each year. The Note Purchase Agreement requires PrimeWest to make four annual principal repayments of US$31,250,000 commencing May 7, 2007.



Net Debt to Cash Flow Multiple At Year End

PrimeWest issued the 7.5% (Series I) and 7.75% (Series II) Debentures in the third quarter of 2004 for proceeds of $150.0 million and $100.0 million, respectively.

The Series I Debentures pay interest semi-annually on March 31 and September 30 and have a maturity date of September 30, 2009. The Series I Debentures are convertible at the option of the holder at a conversion price of $26.50 per Trust Unit. PrimeWest has the option to redeem the Series I Debentures at a price of $1,050 per Series I Debenture after September 30, 2007 and on or before September 30, 2008, and at a price of $1,025 per Series I Debenture after September 30, 2008 and before maturity. On redemption or maturity the Trust may elect to satisfy its obligation to repay the principal by issuing Trust Units.

The Series II Debentures pay interest semi-annually on June 30 and December 30 and have a maturity date of December 31, 2011. The Series II Debentures are convertible at the option of the holder at a conversion price of $26.50 per Trust Unit. PrimeWest has the option to redeem the Series II Debentures at a price of $1,050 per Series II Debenture after December 31, 2007 and on or before December 31, 2008, at a price of $1,025 per Debenture after December 31, 2008 and on or before December 31, 2009, and after December 31, 2009 and before maturity at a price of $1,000 per Series II Debenture. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal by issuing Trust Units.

PrimeWest's net debt at December 31, 2005 was lower than at December 31, 2004 due to the conversion of $114.3 million of Series I and $72.9 million of Series II Debentures, offset by accretion of $1.0 million. In addition, cash flow from operations in excess of distributions allowed for the repayment of $111.0 million of the bank credit facility.

Unitholders' Equity

The Trust had 79,666,352 Trust Units outstanding at December 31, 2005 compared to 69,886,111 Trust Units at the end of 2004. In addition, there were 1,219,335 Exchangeable Shares (see below) outstanding at year-end, exchangeable into a total of 687,693 Trust Units. The weighted average number of Trust Units, including those issuable by the exchange of Exchangeable Shares, was 75,808,919 Trust Units for the twelve month period ended December 31, 2005 compared to 59,482,034 in 2004.

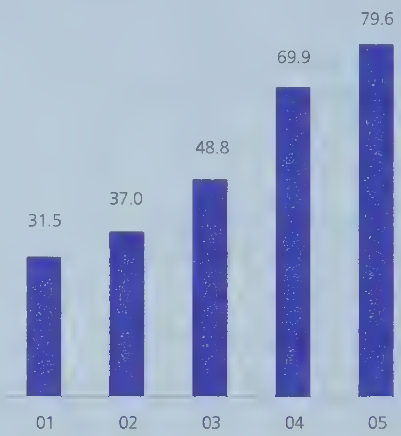
During the year, 487,421 Trust Units were issued to employees pursuant to the LTIP.

During 2005, PrimeWest issued 262,347 Trust Units under the DRIP for $7.9 million (2004 – 268,677 Trust Units, $6.5 million), 932,142 Trust Units for $27.4 million pursuant to the PREP (2004 – 1,311,462 Trust Units, $32.0 million) and 704,806 Trust Units for $20.4 million pursuant to the OTUPP (2004 - 894,167 Trust Units, $21.5 million).

The DRIP gives Canadian and U.S. Unitholders the opportunity to reinvest their monthly distributions at a 5% discount to the volume-weighted average market price of the Trust Units. As an alternative to the DRIP component of the Plan, the PREP allows eligible Canadian Unitholders to elect to receive a premium cash distribution of up to 102% of the cash that the Unitholder would otherwise have received on the distribution date, subject to proration in certain events. The OTUPP gives Canadian Unitholders an opportunity to purchase additional Trust Units directly from PrimeWest at the same 5% discount. The DRIP and PREP components are mutually exclusive. Participation in the OTUPP requires enrolment in either the DRIP or PREP.

These plan components benefit Unitholders by offering alternatives to maximize their investment in PrimeWest, while providing the Trust with an inexpensive method of raising additional capital. The Trust expects interest in these plans in 2006 to be similar to 2005. Proceeds from these plans are used for debt reduction of PrimeWest's credit facility and to help fund ongoing capital development programs.

For additional information or to join these plans, contact the Plan Agent for the DRIP, OTUPP and PREP, Computershare Trust Company of Canada, at 1-800-564-6253, or visit PrimeWest's website at www.primewestenergy.com.



Trust Units Outstanding at Year End (millions)

Exchangeable Shares

Exchangeable Shares were issued in connection with both the Venator Petroleum Company Ltd. acquisition in April 2000 and the Cypress Energy Inc. acquisition in March 2001. These shares were issued to provide a tax-deferred rollover of the adjusted cost base from the shares being exchanged to the Exchangeable Shares.

In 2005, 94,340 (2004 – 94,340) Exchangeable Shares were issued pursuant to the Special Employee Retention Plan (SERP). See note 18 to the Consolidated Financial Statements.

The Exchangeable Shares do not receive cash distributions. In lieu of receiving cash distributions, the number of Trust Units that the exchangeable shareholder will receive upon exchange increases each month based on the distribution amount divided by the market price of the Trust Units on the 15th day of each month.

At December 31, 2005, there were 1,219,335 Exchangeable Shares outstanding. The exchange ratio was 0.56399:1 Trust Units for each Exchangeable Share at year end.

For purposes of calculating basic per Trust Unit amounts, these Exchangeable Shares have been assumed to be exchanged into Trust Units at the current exchange ratio.

Cash Distributions

Since August 2003, PrimeWest has followed a strategy of targeting a distribution payout ratio within 70-90% of cash flow, calculated on an annual basis. The recent strength in commodity prices has increased the Trust's cash flow from operations available for distribution to Unitholders. The Board of Directors of PrimeWest will continue to consider a variety of factors in establishing the monthly distribution level. These factors include, but are not limited to: commodity price outlook, cash flow forecast, capital development plans, debt levels, taxability considerations and competitive industry distribution practices.

Cash distributions for 2005 were $276.6 million or $3.66 per Trust Unit, representing a payout ratio of approximately 67%, versus 2004 amounts of $196.1 million or $3.30 per Trust Unit, representing a payout ratio of approximately 74%.

Distribution payments to U.S. Unitholders are subject to a 15% Canadian withholding tax, which is deducted from the distribution amount prior to deposit into accounts.

Cash Flow Sensitivities

	Increase to Annual Cash Flow $/Trust Unit
Crude oil price (US$1.00/bbl WTI increase)	$ 0.03
Natural gas price ($0.10/mcf increase)	$ 0.06
Exchange rate (US$0.01 decrease)	$ 0.09
Short-term interest rate (1% decrease)	$ 0.02
Production (1,000 BOE/day increase)	$ 0.20

(1) Without the effect of hedging and assuming no change in operating costs and royalty costs.

The figures in the above table are provided for directional information only and are based on the number of Trust Units outstanding as at December 31, 2005. Should changes to the commodity price, interest rate, exchange rate or production levels noted above take place, it should not be assumed that a corresponding change would be made to the distribution level.

Contractual Obligations

PrimeWest enters into many contractual obligations as part of conducting day-to-day business. Material contractual obligations include debt obligations, office lease rental commitments that run from 2006 through 2009 and various pipeline transportation commitments that run through 2011. The details of the timing of these contractual obligations are included in the following table.

		Payments Due by Period			
As at December 31, 2005 ($ millions)	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Long-term debt obligations	$ 298.4	$ -	$ 225.7	$ 72.7	$ -
Debentures	57.6	-	-	33.6	24.0
Office lease rental obligations	11.4	3.7	6.9	0.8	-
Pipeline transportation obligations	11.5	7.2	3.7	0.5	0.1
Derivative liability	11.5	11.3	0.2	-	-
Total contractual obligations	$ 390.4	$ 22.2	$ 236.5	$ 107.6	$ 24.1

As part of PrimeWest's 2002 internalization transaction, which closed on November 6, 2002, PrimeWest agreed to issue 377,360 Exchangeable Shares to certain executive officers pursuant to the SERP. On November 6, 2004 and 2005, 94,340 Exchangeable Shares were issued to those officers. An additional 94,340 shares will be issued on November 6, 2006 and 2007. For the 12 months ended December 31, 2005, $1.8 million was recorded in non-cash G&A expense related to the SERP.

Quarterly Performance – Selected Measures

	2005 (Restated)(1)				2004 (Restated)(1)			
($ millions, except per Trust Unit amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net revenues(2)	$ 236.4	$ 101.5	$ 155.3	$ 111.2	$ 158.2	$ 84.5	$ 84.9	$ 75.2
Net income	101.5	27.3	54.7	24.0	42.2	27.1	16.5	19.6
Cash flow	132.5	106.4	95.5	79.7	83.3	66.8	58.2	58.5
Net income per Trust Unit – Basic	1.27	0.35	0.74	0.34	0.59	0.44	0.30	0.39
Net income per Trust Unit – Diluted	1.23	0.35	0.72	0.34	0.58	0.44	0.30	0.39
Cash flow per Trust Unit – Basic	1.66	1.36	1.29	1.12	1.17	1.09	1.05	1.16
Cash flow per Trust Unit – Diluted	$ 1.60	$ 1.31	$ 1.21	$ 1.04	$ 1.07	$ 1.08	$ 1.05	$ 1.15

(1) See note 3 to the Consolidated Financial Statements.

(2) Net revenues equals revenues from the sale of crude oil, natural gas and natural gas liquids less Crown and other royalties plus unrealized gain or loss on derivatives, gain on sale of marketable securities and other income.

The above table highlights PrimeWest's performance by selected measures for the quarter ended December 31, 2005, and the preceding seven quarters.

Net revenues are primarily impacted by commodity prices, production volumes and royalties. Net revenues are also impacted by non-cash items including the unrealized gain or loss on derivatives and the gain on sale of marketable securities.

Net income and net income per Trust Unit are secondary measures for a royalty trust because they include both cash and non-cash items. The non-cash items such as DD&A, future income taxes, unrealized foreign exchange gains or losses, and unrealized gains or losses on derivatives will not affect PrimeWest's ability to pay a monthly distribution.

Annual Performance – Selected Measures

($ millions, except per Trust Unit amounts)		2005		2004 Restated [(1)]		2003 Restated [(1)]
Gross revenue (net of transportation expense)	$	749.7	$	513.7	$	434.6
Net income	$	207.5	$	105.4	$	102.7
Net income per Trust Unit – Basic	$	2.73	$	1.77	$	2.23
Net income per Trust Unit – Diluted	$	2.66	$	1.77	$	2.22
Total assets	$	2,131.9	$	2,240.9	$	1,690.5
Long-term financial liabilities [(2)]	$	394.8	$	696.6	$	269.8

(1) See note 3 to the Consolidated Financial Statements.

(2) Includes long-term debt, derivative liabilities and the asset retirement obligation.

The above table highlights selected performance measures for the years ended December 31, 2005, 2004 and 2003.

The increase in gross revenues net of transportation from $434.6 million in 2003 to $749.7 million in 2005 was due to increases in production volumes and realized commodity prices over the period. The increase in production volumes is mainly due to the Calpine asset acquisition in the third quarter of 2004.

Net income has increased from 2003 to 2005 due to increases in gross revenues (described above), offset by increases to royalties, operating expense, cash G&A expense and interest expense. Increases to non-cash expenses including DD&A and unrealized losses on derivatives, and reductions to future income tax recoveries have negatively impacted net income during the period. The increases to the operating and cash G&A expenses are due mainly to additional production volumes and staffing requirements resulting from corporate and asset acquisitions.

Total assets at December 31, 2004 exceed the balance at December 31, 2003 mainly due to the Calpine asset acquisition.

Long-term financial liabilities increased from $269.8 million at December 31, 2003 to $696.6 million at December 31, 2004 due primarily to the issuance of the Series I and Series II Debentures and the drawdown on the credit facility to finance the Calpine asset acquisition. The decrease in the liabilities from December 31, 2004 to December 31, 2005 is due to the conversion of $186.2 million of Debentures into Trust Units and to the repayment of $111.0 million of the bank credit facility.

Critical Accounting Estimates

PrimeWest's financial statements have been prepared in accordance with GAAP. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discussion reviews such accounting policies and is included in this annual report to aid the reader in assessing the critical accounting policies and practices of the Trust and the likelihood of materially different results being reported. PrimeWest's management reviews its estimates regularly, but new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. The Trust may realize different results from the application of new accounting standards proposed and/or implemented, from time to time, by various rule-making bodies.

Disclosure of Oil and Natural Gas Reserves

Disclosure in respect of the reserves of PrimeWest is for the year ended December 31, 2005 and is derived from the GLJ Report. Capitalized terms not otherwise defined in respect of PrimeWest's reserves and production have the meaning provided for them in NI 51-101.

Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas liquids, including condensate, and natural gas that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made).

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (i.e. it is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves). In accordance with this definition, the level of certainty targeted by the reporting entity should result in at least a 90% probability that the quantities recovered will equal or exceed the estimated Proved reserves.

For Probable reserves, which are by definition less certain to be recovered than Proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves. With respect to the consideration of certainty, in order to report reserves as Proved plus Probable, the level of certainty targeted by the reporting entity should result in at least a 50% probability that the quantities recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

The oil and natural gas reserve estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in PrimeWest's plans. The effect of changes in Proved oil and natural gas reserves on the financial results and position of PrimeWest are described under the heading Full Cost Accounting for Oil and Natural Gas Activities.

In addition to the categorization of its reserves into "Gross" and "Net", as required by NI 51-101, PrimeWest also uses the term "Company Interest' to describe its reserves. Company Interest reserves include working interest and royalties receivable by PrimeWest, with no deduction of royalties payable. PrimeWest reported its reserves on a Company Interest basis prior to the implementation of NI 51-101 and PrimeWest continues to provide this disclosure for comparability purposes.

PrimeWest's disclosure of reserves data and other oil and natural gas information is made in conformity with NI 51-101. There are differences between the requirements under NI 51-101 and those imposed by the SEC, including with respect to the disclosure of Proved Reserves, Probable Reserves and estimated future net cash flows from Reserves. Further information in this regard is set forth under the heading Statement of Reserves Data and Other Oil and Gas Information - General in PrimeWest's Annual Information Form dated March 15, 2006.

FULL COST ACCOUNTING FOR OIL AND NATURAL GAS ACTIVITIES

PrimeWest adopted Canadian Institute of Chartered Accountants (CICA) Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting – Full Costs" on January 1, 2004. The guideline requires cost centres be tested for recoverability using undiscounted future cash flows from Proved reserves which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre is written down to its fair value. Fair value is estimated using accepted present value techniques that incorporate risks and other uncertainties when determining expected cash flows.

DEPLETION EXPENSE

PrimeWest uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development activities, whether successful or not, are capitalized. The aggregate of net capitalized costs and estimated future development costs less estimated salvage values is amortized using the unit of production method based on estimated Proved oil and natural gas reserves. An increase in estimated Proved oil and natural gas reserves would result in a corresponding reduction in depletion expense. A decrease in estimated future development costs would result in a corresponding reduction in depletion expense.

FAIR VALUE OF DERIVATIVE INSTRUMENTS

As part of its financial management strategy, PrimeWest utilizes financial derivatives, including commodity prices hedges, to manage market risk. The purpose of hedging is to provide an element of stability to PrimeWest's cash flow in a volatile commodity price environment. Effective January 1, 2004, PrimeWest adopted CICA Accounting Guideline 13, (AcG-13) "Hedging Relationships".

The estimation of the fair value of certain hedging derivatives requires considerable judgment. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility and that, when compared with PrimeWest's outstanding hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, PrimeWest changed its accounting policy with respect to accounting for asset retirement obligations. CICA section 3110 requires the fair value of asset retirement obligations to be recorded when they are incurred rather than merely accumulated or accrued over the useful life of the respective asset.

PrimeWest, under the current policy, is required to provide for future removal and site restoration costs. PrimeWest must estimate these costs in accordance with existing laws, contracts and policies. These estimated costs are charged to earnings and the appropriate liability account over the expected service life of the asset. Contingent liabilities are charged to earnings when management is able to determine the amount and the likelihood of the future obligation.

LEGAL, ENVIRONMENTAL REMEDIATION AND OTHER CONTINGENT MATTERS

The Trust is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations and whether that loss can reasonably be estimated. When the loss is determined, it is charged to earnings. PrimeWest's management must continually monitor known and potential contingent matters and make appropriate provisions through charges to earnings when warranted by circumstance.

INCOME TAX ACCOUNTING

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

BUSINESS COMBINATIONS

Since inception, PrimeWest has grown considerably through combining with other businesses. PrimeWest uses the purchase method to account for its acquisitions. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and natural gas properties primarily involves placing a value on the oil and natural gas reserves. The valuation of oil and natural gas reserves entails the process described above under Proved, Probable and Proved Plus Probable Oil and Natural Gas Reserves, but also incorporates the use of economic forecasts that estimate future changes in prices and costs. This methodology is also used to value unproved oil and natural gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of Proved reserves.

GOODWILL

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise, the determination of goodwill is also imprecise. In accordance with CICA section 3062, Goodwill and Other Intangible Assets, goodwill is not amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires PrimeWest to determine the fair value of its assets and liabilities. Such a process involves considerable judgment.

Recent Accounting Pronouncements Issued But Not Implemented

The following new or amended standards and guidelines were issued but not implemented by PrimeWest.

EXCHANGEABLE SHARE ACCOUNTING

In January 2005 the CICA issued Emerging Issues Committee (EIC) 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts." EIC 151 deals with the presentation of exchangeable securities on the balance sheet. The EIC states that exchangeable securities should be included as part of Unitholders' equity only if the holders of the exchangeable securities are entitled to receive distributions of earnings economically equivalent to distributions received by units of the income trust and if the exchangeable securities ultimately are required to be exchanged for units of the income trust as a result of the passage of a fixed period of time. The Trust has reviewed the impact of the pronouncement and determined that it does not materially impact its Consolidated Financial Statements.

FINANCIAL INSTRUMENTS

In May 2005, the CICA issued the Handbook Section "Financial Instruments – Recognition and Measurement". This Section establishes standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. The new section will apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Trust is reviewing the section and has yet to determine the impact on the Consolidated Financial Statements.

Business Risks

PrimeWest's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and natural gas royalty trust sector and the conventional oil and natural gas exploration and production sector. The Trust's financial position, results of operations, and cash available for distribution to Unitholders are directly impacted by these factors. These factors are discussed below.

COMMODITY PRICE, FOREIGN EXCHANGE AND INTEREST RATE RISK

The two most important factors affecting the level of cash distributions available to Unitholders are the level of production achieved by PrimeWest, and the price received for its products. These prices are influenced in varying degrees by factors outside of the Trust's control. These factors include:

- World market forces, specifically the actions of OPEC and other large crude oil producing countries including Russia, and their implications for the supply of crude oil;
- World and North American economic conditions, which influence the demand for crude oil and natural gas and the level of interest rates set by the governments of Canada and the U.S.;
- Weather conditions that influence the demand for natural gas and heating oil;

- The Canadian/U.S. currency exchange rate, which affects the price received for crude oil, as the price of crude oil is referenced in U.S. dollars;
- Transportation availability and costs; and
- Price differentials between world and North American markets based on transportation costs to major markets and quality of production.

To mitigate these risks, PrimeWest has an active hedging program in place based on an established set of criteria that has been approved by the Board of Directors. The results of the hedging program are reviewed against these criteria and the results are actively monitored by the Board.

Beyond the hedging strategy, PrimeWest also mitigates risk by having a diversified marketing portfolio, by transacting with a number of counterparties and by limiting exposure to each counterparty. In 2005, approximately 25% of the Trust's natural gas production was sold to aggregators and 75% into the Alberta short-term or export long-term markets.

The contracts that PrimeWest has with aggregators vary in length. They represent a blend of domestic and U.S. markets and fixed and floating prices designed to provide price diversification to our revenue stream.

The primary objectives of our hedging program are to stabilize cash flow, reducing its volatility, to lock in the economics of major acquisitions and to protect our capital structure when commodity prices cycle downwards, while retaining some exposure to pricing upside. In 2005, PrimeWest recorded a loss of $44.3 million from commodity hedges ($0.54 per Trust Unit), while in 2004, PrimeWest recorded a loss of $28.2 million ($0.45 per Trust Unit) to our cash flow through various physical and financial hedging transactions.

OPERATIONAL AND OTHER BUSINESS RISKS

PrimeWest is also exposed to a number of risks related to its activities within the oil and natural gas industry that also have an impact on the amount of cash available to Unitholders. These risks and the manner in which PrimeWest seeks to mitigate these risks include, but are not limited to:

Risk	We Mitigate By
Production Risk associated with the production of oil and natural gas – includes well operations, processing and the physical delivery of commodities to market.	Performing regular and proactive protective well, facility and pipeline maintenance supported by telemetry, physical inspection and diagnostic tools.
Commodity Price Fluctuations in natural gas, crude oil and natural gas liquids prices.	Hedging. See note 17 to the Consolidated Financial Statements.
Transportation Market risk related to the availability of transportation to market and potential disruption in delivery systems.	Diversifying the transportation systems on which we rely to get our product to market.
Natural Production Decline Development risk associated with capital enhancement activities undertaken – the risk that capital spending on activities such as drilling, well completions, well workovers and other capital activities will not result in reserve additions or in added production in quantities sufficient to replace annual production declines.	Diversifying our capital spending program over a large number of projects so that excessive capital is not risked on any one activity. We also have a highly skilled technical team of geologists, geophysicists and engineers working to apply the latest technology in planning and executing capital programs. Capital is spent only after strict economic criteria for estimated production and reserve additions are met.
Acquisitions Acquisition risk associated with acquiring producing properties at sufficiently low cost to renew our inventory of assets.	Continually scanning the marketplace for opportunities to acquire assets. Our technical acquisition specialists evaluate potential corporate or property acquisitions and identify areas for value enhancement through operational efficiencies or capital investment. All prospects are subjected to rigorous economic review against established acquisition and economic hurdle rates. In some cases, we may also hedge commodity prices to protect the acquisition economics in the near term.

Reserves	
Reserve risk in respect of the quantity and quality of recoverable reserves estimated versus ultimately recovered.	Contracting our reserves evaluation to a reputable third-party consultant, GLJ. The work and independence of GLJ is reviewed by the Operations and Reserves Committee of the Board of Directors of PrimeWest. Our strategy is to invest in mature, longer-life properties having a higher proved producing component in which the reserve risk is generally lower and cash flows are more stable and predictable.
Environmental Health and Safety (EH&S)	
Environmental, health and safety risks associated with oil and natural gas properties and facilities.	Establishing and adhering to strict guidelines for EH&S including training, proper reporting of incidents, supervision and awareness. PrimeWest has active community involvement in field locations including regular meetings with stakeholders in our operational areas. PrimeWest carries adequate insurance to cover property losses, liability and business interruption. These risks are reviewed regularly by the Corporate Governance and EH&S Committee of the Board of Directors, which acts as PrimeWest's Environmental, Health and Safety Committee.
Regulation, Tax and Royalties	
Changes in government regulations, including reporting requirements, income tax laws, operating practices, environmental protection requirements and royalty rates.	Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations.
Liability of Unitholders is Uncertain	
There is no statutory protection for Unitholders from liabilities of the Trust arising prior to July 1, 2004.	Limiting the business of the Trust to the right to receive the net cash flow of PrimeWest Energy Inc. All of the oil and natural gas business operations of PrimeWest are conducted by PrimeWest Energy Inc. PrimeWest Energy Inc. has a vigorous EH&S program as well as significant insurance protection.

Income Taxes – Unitholders – 2005

For the 2005 taxation year, Canadian Unitholders of PrimeWest were paid $3.66 per Trust Unit in distributions. Of this distribution amount, 25% or $0.92 per Trust Unit is deemed a tax-deferred return of capital, and 75% or $2.74 per Trust Unit is taxable to Unitholders as other income (taxed at the same rate as interest income).

For Unitholders resident in the U.S., the taxability of distributions is calculated using U.S. tax rules, which allow for the deduction of Crown royalties and accounting-based depletion. Distributions are taxable as dividends with 81.25% of the 2005 distributions taxable as a "qualified dividend" and the remaining 18.75% treated as a tax-deferred return of capital. A 15% withholding tax applies to distributions paid to U.S. Unitholders. Further details regarding the withholding tax is available on PrimeWest's website at www.primewestenergy.com.

For Canadian and U.S. Unitholders, the tax-deferred return of capital portion reduces the Unitholder's adjusted cost base for purposes of calculating a capital gain or loss upon ultimate disposition of their Trust Units. Unitholders contemplating a disposition may wish to consult the "Unitholder Info" section on PrimeWest's website and use the adjusted cost base calculator.

PrimeWest recommends that all Unitholders contact their tax advisors to discuss tax-related issues.

Management's Responsibility for Financial Statements and Management's Discussion and Analysis

The Consolidated Financial Statements of PrimeWest Energy Trust and Management's Discussion and Analysis (MD&A) were prepared by, and are the responsibility of, the management of PrimeWest Energy Inc. and PrimeWest Gas Corp. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada. The financial and operating information presented in this annual report is consistent with that shown in the Consolidated Financial Statements.

Management has designed and maintains a system of internal controls to safeguard assets and ensure that transactions are properly authorized and recorded and form part of these Consolidated Financial Statements. Where estimates are used in the preparation of these Consolidated Financial Statements, management has ensured that careful judgment has been made and that these estimates are reasonable, based on all information known at the time the estimates are made.

The Board of Directors of PrimeWest is responsible for ensuring that management fulfills its responsibilities for financial reporting, and it has reviewed and approved these Consolidated Financial Statements and MD&A. The Board carries out this responsibility through the Audit and Finance Committee, which consists only of independent directors of the Board.

Unitholders have appointed the external audit firm of PricewaterhouseCoopers LLP to express its opinion on the Consolidated Financial Statements. The auditors have full and unrestricted access to the Audit and Finance Committee to discuss their findings.

Don Garner

President and Chief Executive Officer

Dennis Feuchuk

Vice-President, Finance and Chief Financial Officer

February 23, 2006

AUDITORS' REPORT

TO THE UNITHOLDERS OF PRIMEWEST ENERGY TRUST:

We have audited the Consolidated Balance Sheets of PrimeWest Energy Trust as at December 31, 2005 and 2004, and the Consolidated Statements of Income, Changes in Unitholders' Equity and Cash Flows for each of the years in the three-year period ended December 31, 2005. These financial statements are the responsibility of the management of PrimeWest. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free from material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall Financial Statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004, and the results of its operations and cash flows for each of the years in the three-year period ended December 31, 2005, in accordance with Canadian Generally Accepted Accounting Principles.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 10, 2006

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA – U.S. REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Trust's financial statements, such as the change described in notes 3 and 20 to the consolidated financial statements. Our report to the Unitholders dated February 10, 2006 is expressed in accordance with Canadian reporting standards, which do not require a reference to such a change in accounting principles in the Auditors' Report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta

February 10, 2006

CONSOLIDATED BALANCE SHEETS

As at December 31 ($ millions)	2005	2004 (restated – see note 3)
ASSETS		
Current assets		
Cash and cash equivalents	$ 36.8	$ 54.4
Marketable securities (note 4)	-	68.6
Accounts receivable	125.0	96.9
Assets held for sale (note 6)	-	5.4
Future income taxes (note 16)	3.9	-
Prepaid expenses	16.3	10.9
Inventory	3.5	5.8
	185.5	242.0
Cash reserved for site restoration and reclamation (note 10)	9.2	10.3
Other assets and deferred charges (note 7)	8.8	10.9
Derivative asset	-	0.6
Property, plant and equipment (note 6)	1,859.9	1,908.6
Goodwill	68.5	68.5
	$ 2,131.9	$ 2,240.9
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 50.2	$ 47.7
Accrued liabilities	75.9	72.3
Derivative liability (note 17)	11.3	0.5
Accrued distributions to Unitholders	25.0	17.7
	162.4	138.2
Long-term debt (note 8)	354.2	656.3
Derivative liability (note 17)	0.2	-
Future income taxes (note 16)	214.8	225.7
Asset retirement obligation (note 9)	40.4	40.3
	772.0	1,060.5
UNITHOLDERS' EQUITY		
Net capital contributions (note 11)	2,294.3	2,042.0
Capital issued but not distributed	3.6	3.3
Convertible Unsecured Subordinated Debentures (note 8)	1.8	8.1
Contributed surplus (note 12)	8.7	6.4
Accumulated income	303.8	96.3
Accumulated cash distributions	(1,244.3)	(967.7)
Accumulated dividends	(8.0)	(8.0)
	1,359.9	1,180.4
	$ 2,131.9	$ 2,240.9

Commitments and contingencies (note 18). The accompanying notes form an integral part of these financial statements.

Harold P. Milavsky
Chair of the Board of Directors

Don Garner
President and Chief Executive Officer

CONSOLIDATED STATEMENTS OF CHANGES IN UNITHOLDERS' EQUITY

For the years ended December 31 ($ millions)	2005	2004 (restated – see note 3)	2003 (restated – see note 3)
Unitholders' equity, beginning of year	$ 1,180.4	$ 1,014.0	$ 847.1
Adjustment to Unitholders' equity at beginning of period to adopt:			
New oil and gas accounting standard (note 3)	-	(233.3)	-
Fair value method for unit-based compensation (note 3)	-	-	(6.7)
Net income for the year	207.5	105.4	102.7
Net capital contributions (note 11)	252.3	481.4	256.7
Capital issued but not distributed	0.3	(1.9)	4.3
Convertible Unsecured Subordinated Debentures	(6.3)	8.1	-
Contributed surplus	2.3	2.8	2.5
Cash distributions (note 14)	(276.6)	(196.1)	(192.6)
Unitholders' equity, end of year	$ 1,359.9	$ 1,180.4	$ 1,014.0

Consolidated Statements of Cash Flow

For the years ended December 31 ($ millions)	2005	2004 (restated – see note 3)	2003 (restated – see note 3)
OPERATING ACTIVITIES			
Net income for the year	$ 207.5	$ 105.4	$ 102.7
Add/(deduct):			
Items not involving cash from operations			
Depletion, depreciation and amortization	230.2	197.3	197.4
Non-cash general and administrative	5.4	4.1	3.1
Non-cash foreign exchange gain	(4.9)	(11.9)	(12.1)
Cash distributions from marketable securities	1.2	4.1	-
Gain on sale of marketable securities (note 4)	(27.2)	-	-
Unrealized loss/(gain) on derivatives	11.6	(0.1)	-
Future income tax recovery	(14.8)	(34.3)	(75.4)
Accretion on asset retirement obligation	2.5	2.0	1.2
Other non-cash items	2.6	0.2	(0.3)
Cash flow from operations	414.1	266.8	216.6
Expenditures on site restoration and reclamation	(8.7)	(4.6)	(2.2)
Change in non-cash working capital	(28.0)	11.9	5.3
	377.4	274.1	219.7
FINANCING ACTIVITIES			
Proceeds from issue of Trust Units (net of costs)	20.4	441.0	240.3
Proceeds from issue of Debentures	-	250.0	-
Net cash distributions to Unitholders (note 14)	(241.5)	(159.6)	(172.5)
Increase (decrease) in bank credit facilities	(111.0)	166.0	(137.0)
Increase in Senior Secured Notes	-	-	174.0
Increase in deferred charges	-	(10.0)	(1.5)
Change in non-cash working capital	4.2	10.9	(3.6)
	(327.9)	698.3	99.7
INVESTING ACTIVITIES			
Expenditures on property, plant and equipment	(192.5)	(129.7)	(105.8)
Acquisition of capital/corporate assets	-	(807.4)	(210.1)
Proceeds on disposal of property, plant and equipment	26.0	96.5	2.3
Investment in marketable securities (note 4)	-	(72.7)	-
(Increase) decrease in cash reserved for future site restoration and reclamation	1.1	(2.1)	(6.6)
Proceeds on disposal of marketable securities	94.5	-	-
Change in non-cash working capital	3.8	(5.1)	6.4
	(67.1)	(920.5)	$ (313.8)
(Decrease)/Increase in cash and cash equivalents for the year	$ (17.6)	$ 51.9	$ 5.6
Cash and cash equivalents (bank overdraft) beginning of the year	54.4	2.5	(3.1)
Cash and cash equivalents end of the year	$ 36.8	$ 54.4	$ 2.5
Cash interest paid	$ 23.8	$ 15.0	$ 13.1
Cash taxes paid	$ 5.4	$ 3.8	$ 3.9

CONSOLIDATED STATEMENTS OF INCOME

For the years ended December 31 ($ millions, except per Trust Unit amounts)	2005	2004 (restated – see note 3)	2003 (restated – see note 3)
REVENUES			
Sales of crude oil, natural gas and natural gas liquids	$ 756.9	$ 521.9	$ 442.9
Crown and other royalties	(172.8)	(119.8)	(101.9)
Unrealized (loss)/gain on derivatives	(11.6)	0.1	-
Gain on sale of marketable securities	27.2	-	-
Other income	4.7	0.6	(2.8)
	604.4	402.8	338.2
EXPENSES			
Operating	117.0	88.9	79.4
Transportation	7.2	8.2	8.3
Cash general and administrative	22.9	19.0	14.5
Non-cash general and administrative (note 13)	5.4	4.1	3.1
Interest	28.3	20.6	15.1
Depletion, depreciation and amortization	230.2	197.3	197.4
Accretion on asset retirement obligations	2.5	2.0	1.2
Foreign exchange gain	(4.6)	(11.7)	(11.9)
	408.9	328.4	307.1
Income before taxes for the year	195.5	74.4	31.1
Income and capital taxes	2.8	3.3	3.8
Future income taxes recovery (note 16)	(14.8)	(34.3)	(75.4)
	(12.0)	(31.0)	(71.6)
Net income for the year	$ 207.5	$ 105.4	$ 102.7
Net income per Trust Unit	$ 2.73	$ 1.77	$ 2.23
Diluted net income per Trust Unit	$ 2.66	$ 1.77	$ 2.22

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(ALL AMOUNTS ARE EXPRESSED IN MILLIONS OF CANADIAN DOLLARS UNLESS OTHERWISE INDICATED)

1. Structure of The Trust

PrimeWest Energy Trust (the Trust) is an open-ended investment trust formed under the laws of Alberta in accordance with a declaration of trust dated August 2, 1996, as Amended. The beneficiaries of the Trust are the holders of Trust Units (the Unitholders).

The principal undertaking of the Trust's operating companies, PrimeWest Energy Inc. and PrimeWest Gas Corp. (collectively referred to as PrimeWest) is to acquire and hold, directly and indirectly, interests in oil and natural gas properties. One of the Trust's primary assets is a royalty entitling it to receive 99% of the net cash flow generated by the oil and natural gas interests owned by PrimeWest. The royalty acquired by the Trust effectively transfers substantially all of the economic interest in the properties to the Trust.

The common shares of PrimeWest Energy Inc. are 100% owned by the Trust. PrimeWest Gas Corp., a wholly owned subsidiary of PrimeWest Energy Inc., was amalgamated with PrimeWest Energy Inc. effective January 1, 2006.

2. Accounting Policies

CONSOLIDATION

These consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries, PrimeWest Energy Inc. and PrimeWest Gas Corp. The Trust, through the royalty, obtains substantially all of the economic benefits of the operations of PrimeWest.

CASH AND CASH EQUIVALENTS

Short-term investments, with maturities less than three months at the date of acquisition, are considered to be cash equivalents and are recorded at cost, which approximates market value.

MARKETABLE SECURITIES

Marketable securities are carried at the lower of cost or market.

INVENTORY

Inventory is measured at lower of cost and net realizable value.

GOODWILL

Goodwill represents the excess of purchase price over fair value of net assets acquired and liabilities assumed. Goodwill is assessed for impairment at least annually. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

PROPERTY, PLANT AND EQUIPMENT

PrimeWest follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings. Renewals and enhancements that extend the economic life of the capital asset are capitalized.

Gains and losses are not recognized on disposition of oil and natural gas properties unless that disposition would alter the rate of depletion by 20% or more.

i) Ceiling test

PrimeWest places a limit on the aggregate cost of capital assets that may be carried forward for depletion against net revenues of future periods (the ceiling test). The ceiling test is an impairment test whereby the carrying amount of capitalized assets is compared to the undiscounted cash flows from Proved reserves plus Unproved properties using management's best estimate of future prices. If the asset value exceeds the undiscounted cash flows the impairment is measured as the amount by which the carrying amount of the capitalized asset exceeds the future discounted cash flows from Proved plus Probable reserves. The discount rate used is the risk-free rate.

ii) Asset retirement obligation

PrimeWest recognizes the future retirement obligations associated with the retirement of property, plant and equipment. The obligations are initially measured at fair value and subsequently adjusted for accretion of discount and changes in the underlying liability. The asset retirement cost is capitalized to the related asset and amortized to earnings over time.

iii) Depletion, depreciation and amortization (DD&A)

Provision for depletion and depreciation is calculated on the unit-of-production method, based on Proved reserves before royalties. Reserves are estimated by independent petroleum engineers. Reserves are converted to equivalent units on the basis of approximate relative energy content. Depreciation and amortization of head office furniture and equipment is provided for at rates ranging from 10-30%.

JOINT VENTURE ACCOUNTING

PrimeWest conducts substantially all of its oil and natural gas production activities through joint ventures, and the accounts reflect only PrimeWest's proportionate interest in such activities.

UNIT-BASED COMPENSATION

PrimeWest accounts for its Unit Appreciation Rights (UARs) issued to employees and the Board of Directors using the fair value method. The fair value of each UAR is estimated on the date of the grant using the Black-Scholes options pricing model and charged to earnings over the vesting period with a corresponding increase to contributed surplus.

INCOME TAXES

The Trust is considered an inter-vivos trust for income tax purposes. As such, the Trust is subject to tax on any taxable income that is not allocated to the Unitholders. Periodically, current taxes may be payable by PrimeWest, depending upon the timing of income tax deductions. Should these taxes prove to be unrecoverable, they will be deducted from royalty income in accordance with the royalty agreement.

Future income taxes are recorded for PrimeWest using the liability method of accounting. Future income taxes are recorded to the extent that the carrying value of PrimeWest's capital assets exceeds the available tax pools.

FINANCIAL INSTRUMENTS

PrimeWest uses financial instruments to manage its exposure to fluctuations in commodity prices and interest rates. PrimeWest does not use financial instruments for speculative trading purposes. The financial instruments are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period.

MEASUREMENT UNCERTAINTY

Certain items recognized in the Financial Statements are subject to measurement uncertainty. The recognized amounts of such items are based on PrimeWest's best information and judgment. Such amounts are not expected to change materially in the near term. They include the amounts recorded for depletion, depreciation and future site restoration costs which depend on estimates of oil and natural gas reserves or the economic lives and future cash flows from related assets.

3. Changes in Accounting Policies

CHANGE IN METHOD OF ACCOUNTING FOR UNIT-BASED COMPENSATION

Beginning January 1, 2005, PrimeWest determined that if a series of assumptions were used, it was possible to use a traditional options pricing model to calculate a reasonable estimate of the fair value of PrimeWest's UARs granted under its Long-Term Incentive Plan (LTIP). Under the fair value method, PrimeWest recognizes compensation expense related to the UARs over the vesting period of the UARs granted with the related credit being charged to contributed surplus. In prior years, PrimeWest had been applying the intrinsic method to value its unit-based compensation whereby the value of the UARs was adjusted at the end of each accounting period to reflect the impact of the reinvestment of cumulative distributions and the changes in the trading price of the Trust Units. The changes in value of the UAR liability were reflected in non-cash G&A on the income statement.

PrimeWest has applied the fair value method retroactively to UARs issued on or after January 1, 2002 and prior periods have been restated. At January 1, 2005 the change in accounting policy resulted in an increase to the future income tax liability of $14.5 million (2004 – $11.2 million), a decrease to net capital contributions of $7.9 million (2004 – $5.3 million), a decrease to the LTIP equity of $20.1 million (2004 – $14.6 million), an increase in contributed surplus of $6.4 million (2004 – $3.6 million) and an increase to accumulated income of $7.1 million (2004 – $5.1 million).

The change in accounting method resulted in an increase to 2005 net income of $52.7 million.

FULL COST ACCOUNTING

The adoption of CICA Accounting Guideline 16 (AcG-16) modifies how the ceiling test is performed resulting in a two stage process. The guideline is effective for fiscal years beginning on or after January 1, 2004. The cost impairment test is a two-stage process, which is performed at least annually. The first stage of the test determines if the cost pool is impaired. An impairment loss exists when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows from Proved reserves plus unproved properties using management's best estimate of future prices. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the carrying amount of capitalized assets exceeds the future discounted cash flows from Proved plus Probable reserves. The discount rate used is the risk free rate.

PrimeWest performed the ceiling test under AcG-16 as of January 1, 2004. The impairment test was calculated using the consultants' average prices at January 1 for the years 2004 to 2008 as follows:

Consultants' Average Price Forecasts	2004	2005	2006	2007	2008
W.T.I. (US$/bbl)	29.21	26.43	25.42	25.38	25.51
AECO (Cdn$/mcf)	5.90	5.33	4.98	4.95	4.92

The ceiling test resulted in a before-tax impairment of $308.9 million and an after-tax impairment of $233.3 million. This write down was recorded to accumulated income in the first quarter of 2004 with the adoption of AcG-16.

ASSET RETIREMENT OBLIGATION

Effective January 1, 2004, the Trust retroactively adopted the CICA Handbook section 3110, "Asset Retirement Obligations". The standard requires the recognition of the liability associated with the future site reclamation costs of tangible long-lived assets. This liability is comprised of the Trust's net ownership interest in producing wells and processing plant facilities. The liability for future retirement obligations is recorded in the financial statements at the time the liability is incurred.

The asset retirement obligation is initially recorded at the estimated fair value as a long-term liability with a corresponding increase to property, plant and equipment. The depreciation of property, plant and equipment is allocated to expense on the unit-of-production basis. The liability is increased each reporting period for the fair value of any new future site reclamation costs and the corresponding accretion on the original provision. The accretion is charged to earnings in the period incurred. The provision will also be revised for any changes to timing related to cash flows or undiscounted reclamation costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligation to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

The cumulative effect of the change in accounting policy was reflected in accumulated income with retroactive restatement of prior period comparatives. At January 1, 2004, this resulted in an increase to the asset retirement obligation of $19.7 million (2003 – $15.3 million), an increase to PP&E of $10.6 million (2003 – $9.0 million), a $5.6 million (2003 – $0.04 million) increase to accumulated income, a decrease of site restoration provision of $17.8 million (2003 – $6.2 million) and an increase to the future tax liability of $3.1 million (2003 – $(0.03) million). See note 9 for the reconciliation of the asset retirement obligation.

Implementation of this accounting standard did not affect the Trust's cash flow or liquidity.

FINANCIAL DERIVATIVES

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline (AcG-13), "Hedging Relationships", which is effective for fiscal years beginning on or after July 1, 2003. AcG-13 addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also established conditions for applying or discontinuing hedge accounting. Under the guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for position hedges with derivatives. The Trust is not applying hedge accounting to its hedging relationships. Derivatives are marked-to-market with the resulting gain or loss reflected in earnings for the reporting period.

4. Marketable Securities

($ millions)	2005	2004
Investment in Viking Energy Royalty Trust	$ -	$ 68.6

PrimeWest sold its 8% ownership in the Viking Energy Royalty Trust in 2005 (formerly Calpine Natural Gas Trust) for net proceeds of $94.5 million resulting in a gain of $27.1 million.

5. Acquisitions

a) On September 2, 2004, PrimeWest Gas Corp. acquired oil and natural gas assets from Calpine Canada. The acquisition was accounted for using the purchase method of accounting with the net assets acquired and consideration paid as follows:

Net Assets Acquired at Assigned Values	($ millions)	Consideration Paid	($ millions)
Petroleum and natural gas assets	$ 745.3		
Inventory	4.2	Cash	$ 747.0
Working capital	2.7	Net closing adjustments	(11.1)
Asset retirement obligation	(12.0)	Costs associated with acquisition	4.3
	$ 740.2		$ 740.2

b) On March 16, 2004, PrimeWest Gas Corp. completed the acquisition of Seventh Energy Ltd. Subsequent to the acquisition, Seventh Energy was amalgamated with PrimeWest Gas Corp. The acquisition was accounted for using the purchase method of accounting with net assets acquired and consideration paid as follows:

Net Assets Acquired at Assigned Values	($ millions)	Consideration Paid	($ millions)
Petroleum and natural gas assets	$ 46.5		
Goodwill	12.4		
Working capital	(2.5)		
Long-term debt assumed	(9.9)		
Office lease obligation	(0.1)		
Asset retirement obligation	(0.5)	Cash	$ 34.6
Future income taxes	(11.1)	Costs associated with acquisition	0.2
	$ 34.8		$ 34.8

6. Property, Plant and Equipment

	2005		
($ millions)	Cost	Accumulated Depletion, Depreciation and Amortization	Net Book Value
Property acquisition oil and natural gas rights	$ 2,677.1	$ (1,260.7)	$ 1,416.4
Drilling and completion	417.9	(110.7)	307.2
Production facilities and equipment	176.6	(48.4)	128.2
Head office furniture and equipment	16.8	(8.7)	8.1
	$ 3,288.4	$ (1,428.5)	$ 1,859.9

	2004		
($ millions)	Cost	Accumulated Depletion, Depreciation and Amortization	Net Book Value
Property acquisition oil and natural gas rights	$ 2,671.2	$ (1,081.0)	$ 1,590.2
Drilling and completion	298.0	(77.1)	220.9
Production facilities and equipment	125.1	(34.0)	91.1
Head office furniture and equipment	12.6	(6.2)	6.4
	$ 3,106.9	$ (1,198.3)	$ 1,908.6

Unproved land costs of $88.0 million (2004 – $103.9 million) and $4.1 million of capital not in use (2004 – $0 million) are excluded from costs subject to depletion and depreciation.

PrimeWest capitalized $3.7 million of G&A costs in 2005 (2004 – $2.9 million).

In February 2005, PrimeWest closed the disposition of a property, receiving the balance of the proceeds of $5.4 million. At December 31, 2004, the amount was recorded as assets held for sale in current assets on the balance sheet.

PrimeWest has performed a ceiling test as at December 31, 2005. The impairment test was calculated using the Consultant's Average Prices at January 1, 2006 for the years 2006 to 2010 as follows:

Consultants' Average Price Forecasts	2006	2007	2008	2009	2010
W.T.I. (US$/bbl)	58.44	57.34	52.70	49.23	47.05
AECO (Cdn$/mcf)	10.93	9.88	8.48	7.59	7.23

Subsequent to 2010, prices increased by approximately 2% per year.

The December 31, 2005 ceiling test resulted in a surplus.

7. Other Assets and Deferred Charges

($ millions)		2005		2004
Deferred charges	$	8.7	$	10.6
Other assets		0.1		0.3
	$	8.8	$	10.9

8. Long-Term Debt

($ millions)		2005		2004
Bank credit facility	$	153.0	$	264.0
Senior Secured Notes		145.4		150.3
Convertible Unsecured Subordinated Debentures		55.8		242.0
	$	354.2	$	656.3

Long-term debt is comprised of bank credit facilities, Senior Secured Notes (Secured Notes) and Convertible Unsecured Subordinated Debentures (Debentures) of $153.0 million, $145.4 million and $55.8 million, respectively.

PrimeWest had a borrowing base of $650 million at December 31, 2005 (2004 – $625 million). The bank credit facilities consist of an available revolving term loan of $458.7 million and an operating facility of $35 million with the balance being attributable to the Secured Notes valued at $156.3 million based on the U.S. dollar exchange rate at the time of the last renewal. In addition to amounts outstanding under the bank credit facility, PrimeWest has outstanding letters of credit in the amount of $6.6 million (2004 – $4.9 million).

Advances under the bank credit facility are made in the form of Banker's Acceptances (BA), prime rate loans or letters of credit. In the case of BAs, interest is a function of the BA rate plus a stamping fee based on the Trust's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the bank's prime rate. For 2005, the effective interest rate on the facilities was 4.0% (2004 – 4.0%).

The bank credit facility revolves until June 30, 2006, by which time the lenders will have conducted their annual borrowing base review. The lenders also have the right to re-determine the borrowing base at one other time during the year. During the revolving phase, the bank credit facility has no specific terms of repayment. At the end of the revolving period, the lenders have the right to extend the revolving period for a further 364-day period or to convert the facility to a term facility. If the lenders convert to a non-revolving facility, 60% of the aggregate principal amount of the loan shall be repayable on the date that is 366 days after such conversion date and the remaining 40% of the aggregate principal amount outstanding shall be repayable on the date that is 365 days after the initial term repayment date.

The Secured Notes in the amount of US$125 million have a final maturity of May 7, 2010, and bear interest at 4.19% per annum, with interest paid semi-annually on November 7 and May 7 of each year. The Note Purchase Agreement requires PrimeWest to make four annual principal repayments of US$31,250,000 commencing May 7, 2007.

Collateral for the Secured Notes and credit facility is a floating charge debenture covering all existing and after acquired property in the principal amount of US$1 billion. The secured parties for the revolving credit facility and Secured Notes have agreed to share the security interests on a pari passu basis.

The costs incurred in connection with the Secured Notes, in the amount of $1.5 million, were classified as deferred charges on the balance sheet and are being amortized over the term of the Notes.

The Secured Notes are the legal obligation of PrimeWest Energy Inc. and are guaranteed by PrimeWest Energy Trust.

The 7.5% (Series I) and 7.75% (Series II) Debentures were issued on September 2, 2004 for proceeds of $150 million and $100 million respectively.

The Series I Debentures pay interest semi-annually on March 31 and September 30 and have a maturity date of September 30, 2009. The Series I Debentures are convertible at the option of the holder at a conversion price of $26.50 per Trust Unit. PrimeWest has the option to redeem the Series I Debentures at a price of $1,050 per Series I Debenture after September 30, 2007 and on or before September 30, 2008, and at a price of $1,025 per Series I Debenture after September 30, 2008 and before maturity. On redemption or maturity the Trust may elect to satisfy its obligation to repay the principal by issuing Trust Units.

The Series II Debentures pay interest semi-annually on June 30 and December 30 and have a maturity date of December 31, 2011. The Series II Debentures are convertible at the option of the holder at conversion price of $26.50 per Trust Unit. PrimeWest has the option to redeem the Series II Debentures at a price of $1,050 per Series II Debenture after December 31, 2007 and on or before December 31, 2008, at a price of $1,025 per Debenture after December 31, 2008 and on or before December 31, 2009 and after December 31, 2009 and before maturity at $1,000 per Series II Debenture. On redemption or maturity the Trust may elect to satisfy its obligations to repay the principal by issuing Trust Units.

Debenture issue costs of $10.0 million were included in deferred charges on the balance sheet and are being amortized over the terms of the Debentures.

In accordance with CICA Handbook section 3860 – "Financial Instruments," the Convertible Unsecured Subordinated Debentures were initially recorded at their fair value of $147.0 million (Series I) and $94.8 million (Series II). The difference between the fair value and proceeds of $8.1 million was recorded in equity ($3.0 million (Series I) and $5.1 million (Series II)).

The Series I and Series II Debentures are being accreted such that the liability at maturity will equal the proceeds of $150 million and $100 million less conversions respectively. During 2005, $114.3 million (2004 – $0.3 million) of Series I and $72.9 million (2004 – $0 million) of Series II Debentures included in long-term debt were converted to equity. Accretion expense was $1.0 million (2004 – $0.4 million).

9. Asset Retirement Obligations

Management has estimated the total future asset retirement obligation based on the Trust's net ownership interest in all wells and facilities. This includes all estimated costs to dismantle, remove, reclaim and abandon the wells and facilities and the estimated time period during which these costs will be incurred in the future.

The following table reconciles the asset retirement obligation associated with the retirement of oil and natural gas properties:

Asset Retirement Obligations ($ millions)	2005	2004
Asset retirement obligation, January 1	$ 40.3	$ 19.7
Liabilities incurred	8.3	13.1
Liabilities settled	(8.7)	(4.6)
Accretion expense	2.5	2.0
Acquisition of capital assets	-	12.0
Disposal of capital assets	(2.0)	(2.4)
Acquisition of Seventh Energy	-	0.5
Asset retirement obligation December 31	$ 40.4	$ 40.3

As at December 31, 2005, the undiscounted amount of estimated cash flows required to settle the obligation is $222.3 million. The estimated cash flow has been discounted using a credit-adjusted risk free rate of 7.0% and an inflation rate of 1.5%. Although the expected period until settlement ranges from a minimum of 1 year to a maximum of 50 years, the costs are expected to be paid over an average of 33.9 years. These future asset retirement costs will be funded from the cash reserved for site restoration and reclamation.

10. Cash Reserve For Site Restoration And Reclamation

Commencing in 1998, funding for the reserve was provided for by reducing distributions otherwise payable based on an amount per BOE produced ($0.50/BOE produced for 2005 and 2004). The cash amount contributed, including interest earned, was $7.6 million in 2005 (2004 – $6.7 million). Actual costs of site restoration and abandonment totaling $8.7 million were paid out of this cash reserve for the year ended December 31, 2005 (2004 – $4.6 million). As at December 31, 2005, the site reclamation fund had a balance of $9.2 million (2004 – $10.3 million).

11. Unitholders' Equity

The authorized capital of the Trust consists of an unlimited number of Trust Units.

Trust Units	Number of Units	Amounts ($ millions)
Balance December 31, 2003	48,751,883	$ 1,532.5[1]
Issued for cash	17,700,000	442.1
Issue expenses	-	(22.6)
Issued on exchange of Exchangeable Shares	833,162	17.0
Issued pursuant to Distribution Reinvestment Plan	268,677	6.5
Issued pursuant to Premium Distribution Plan	1,311,462	32.0
Issued pursuant to Long-Term Incentive Plan	116,233	0.5
Issued pursuant to conversion of Debentures	10,527	0.3
Issued pursuant to Optional Trust Unit Purchase Plan	894,167	21.5
Balance December 31, 2004	69,886,111	$ 2,029.8
Issued on exchange of Exchangeable Shares	91,871	1.7
Issued pursuant to Distribution Reinvestment Plan	262,347	7.9
Issued pursuant to Premium Distribution Plan	932,142	27.4
Issued pursuant to Long-Term Incentive Plan	487,421	1.3
Issued pursuant to conversion of Debentures	7,301,654	193.5
Issued pursuant to Optional Trust Unit Purchase Plan	704,806	20.4
Balance December 31, 2005	79,666,352	$ 2,282.0

(1) Restated – see note 3.

The weighted average number of Trust Units and Exchangeable Shares outstanding for the twelve months ended December 31, 2005 was 75,808,919 (2004 – 59,482,034). For purposes of calculating diluted net income per Trust Unit, 3,247,742 (2004 – 1,868,995) and 2,286,791 Trust Units (2004 –1,247,551) issuable pursuant to the conversion of the Series I and Series II Debentures outstanding respectively and 1,220,958 Trust Units (2004 – 525,129) issuable pursuant to the LTIP were added to the weighted average number.

PRIMEWEST EXCHANGEABLE CLASS A SHARES

PrimeWest has an unlimited number of Exchangeable Shares. The Exchangeable Shares are exchangeable into Trust Units at any time up to March 29, 2010, based on an exchange ratio that adjusts each time the Trust makes distribution to its Unitholders. The exchange ratio, which was 1:1 on the date that the Shares were issued, is based on the total monthly distribution, divided by the closing unit price on the distribution payment date. The exchange ratio on December 31, 2005 was 0.56399:1 (2004 – 0.50408:1).

Exchangeable Shares	Number of Units	Amounts ($ millions)
Balance, December 31, 2003	3,041,123	$ 28.0
Issued for Special Employee Retention Plan	94,340	1.2
Exchanged for Trust Units	(1,841,072)	(17.0)
Balance, December 31, 2004	1,294,391	$ 12.2
Issued for Special Employee Retention Plan	94,340	1.8
Exchanged for Trust Units	(169,396)	(1.7)
Balance, December 31, 2005	1,219,335	$ 12.3

TRUST UNITS AND EXCHANGEABLE SHARES ISSUED AND OUTSTANDING

Number of Shares	2005	2004
Trust Units issued and outstanding	79,666,352	69,886,111
Exchangeable Shares		
Class A Shares		
(2005 – 1,219,335 shares exchangeable at 0.56399;		
2004 – 1,294,391 shares exchangeable at 0.50408)	687,693	652,477
Total Trust Units and Exchangeable Shares issued and outstanding	80,354,045	70,538,588
Convertible Unsecured Subordinated Debentures		
Series I	1,246,981	5,649,849
Series II	874,717	3,773,585
Unit Appreciation Rights	1,220,958	525,129
Total Trust Units and Exchangeable Shares issued and outstanding and Trust Units issuable pursuant to the conversion of the Convertible Unsecured Subordinated Debentures and the Long-Term Incentive Plan	83,696,701	80,487,151

12. Contributed Surplus

Contributed surplus includes the accumulated unit-based compensation charge in respect of PrimeWest's unexercised Unit Appreciation Rights granted under the LTIP on or after January 1, 2002. Upon exercise of the UARs and delivery of the Trust Units, the contributed surplus account is reduced and the amount is transferred to net capital contributions.

($ millions)	
Balance, December 31, 2003	$ 3.6
Non-cash general and administrative expense	3.3
Unit Appreciation Rights exercised	(0.5)
Balance, December 31, 2004	$ 6.4
Non-cash general and administrative expense	3.6
Unit Appreciation Rights exercised	(1.3)
Balance, December 31, 2005	$ 8.7

13. Long-Term Incentive Plan

Under the terms of the LTIP, a maximum of 1,800,000 Trust Units are reserved for issuance pursuant to the exercise of UARs granted to Directors and employees of PrimeWest. Payouts under the plan are based on total unitholder return, calculated using both the change in the Trust Unit price as well as cumulative distributions paid. The Plan requires that a hurdle return of 5% per annum be achieved before payouts accrue. UARs have a term of up to six years and vest equally over a three-year period, except for those issued to the members of the Board, which vest immediately. The Board of Directors has the option of settling payouts under the plan in PrimeWest Trust Units or in cash. To date, all payouts under the plan have been in the form of Trust Units.

Effective January 1, 2005, PrimeWest adopted the fair value method of accounting for its LTIP with respect to UARs granted on or after January 1, 2002. Under this method of accounting, the fair value of the UARs is estimated using a recognized options pricing model on the grant date and is amortized over the vesting period with the amortized amount recorded in non-cash G&A expense offset by an increase to contributed surplus. When the UARs are exercised, contributed surplus is decreased and net capital contributions are increased.

PrimeWest recorded $3.6 million (2004 – $3.3 million) in non-cash G&A expense related to the LTIP.

For the twelve months ended December 31, 2005, PrimeWest used the Black-Scholes Options Pricing Model to calculate the estimated fair value of outstanding UARs issued on or after January 1, 2002. The following assumptions were used to arrive at the estimated fair value:

Weighted Average Assumptions	2005	2004
Risk-free interest rate	3.18%	3.49%
Expected volatility in Trust Unit price	19.8%	22.0%
Expected time until exercise	3 years	3 years
Expected forfeiture rate	13%	13%
Expected annual dividend yield	zero	zero

Summary of Changes	Number of UARs	Weighted Average Exercise Price
Balance outstanding at December 31, 2003	2,046,436	$28.03
Granted	1,495,373	27.94
Forfeited/expired	(141,989)	(29.02)
Exercised	(166,328)	(27.37)
Balance outstanding at December 31, 2004	3,233,492	$28.77
Granted	1,517,674	30.40
Forfeited/expired	(122,873)	(28.44)
Exercised	(458,618)	(28.42)
Balance outstanding at December 31, 2005	4,169,675	$29.09

Summary of UARS Outstanding at December 31, 2005

Year of Grant	UARS Issued and Outstanding	UARS Vested	Range of Exercise Prices	Expiry Date
2002 grants	602,526	600,732	$ 25.90 – 33.94	2008
2003 grants	805,641	516,356	25.25 – 32.24	2009
2004 grants	1,303,893	489,681	24.24 – 32.49	2010
2005 grants	1,457,615	138,464	28.90 – 40.51	2011
Total grants	4,169,675	1,745,233	$ 24.24 – 40.51	

14. Cash Distributions

($ millions)	2005	2004	2003
Cash flow from operations	$ 414.1	$ 266.8	$ 216.6
Deduct amounts to reconcile to distribution:			
Cash retained from cash available for distribution (1)	(129.9)	(64.0)	(15.3)
Contributed to reclamation fund	(7.6)	(6.7)	(8.7)
	$ 276.6	$ 196.1	$ 192.6
Cash distributions to Trust Unitholders	$ 276.6	$ 196.1	$ 192.6
Cash distributions per Trust Unit	$ 3.66	$ 3.30	$ 4.32

(1) The Board of Directors determines the cash distribution level, which results in a discretionary amount of cash being retained.

15. Related Party Transactions

Under the Special Employee Retention Plan (SERP), PrimeWest agreed to issue 94,340 Exchangeable Shares to certain executive officers on each of the second, third, fourth and fifth anniversaries of the completion of the internalization transaction, which closed on November 6, 2002. In November 2005, 94,340 exchangeable shares were issued relating to the SERP. For the twelve months ended December 31, 2005, $1.8 million (2004 – $0.9 million) was recorded in non-cash G&A expense related to the SERP.

16. Income Taxes

PrimeWest and its subsidiaries had no taxable income for 2005, 2004 and 2003, as tax pool deductions and the royalty payable were sufficient to reduce taxable income in these entities to nil.

The future income tax asset and liability result from temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases.

($ millions)	2005	2004
Derivative liabilities	$ 3.9	$ -
Future income tax asset	$ 3.9	$ -

($ millions)	2005	2004 Restated
Loss carry forwards	$ (1.2)	$ (1.4)
Capital assets	224.8	236.9
Foreign exchange gain on long-term debt	4.8	3.7
Asset retirement obligation	(13.6)	(13.5)
Future income tax liability	$ 214.8	$ 225.7

The provisions for income taxes varies from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

($ millions)	2005	2004 Restated	2003 Restated
Income before taxes	$ 195.5	$ 74.4	$ 31.1
Computed income tax expense (recovery) at the Canadian statutory rate of 37.62% (2004 – 38.87%; 2003 – 40.62%)	73.5	28.9	12.6
Increase (decrease) resulting from:			
Non-deductible Crown royalties and other payments, net of ARTC	0.3	0.3	0.3
Federal resource allowance	(12.3)	(9.2)	(17.4)
Change in income tax rate	(2.7)	(7.0)	(42.4)
Foreign exchange gain on long-term debt	(0.9)	(2.2)	(2.4)
Amounts included in Trust income and other	(72.7)	(45.1)	(26.1)
Future income tax recovery	$ (14.8)	$ (34.3)	$ (75.4)

17. Financial Instruments

a) Commodity Price Risk Management

PrimeWest generally sells its oil and natural gas under short-term market-based contracts. Derivative financial instruments, options and swaps may be used to hedge the impact of oil and natural gas price fluctuations.

A summary of these contracts in place at December 31, 2005 follows:

CRUDE OIL

Period	Volume (bbls/day)	Type	WTI Price (US$/bbl)
Jan – Mar 2006	1000	Costless Collar	35.00/49.90
Jan – Mar 2006	500	Costless Collar	40.00/60.25
Jan – Mar 2006	500	Costless Collar	40.00/71.75
Jan – Mar 2006	500	Costless Collar	50.00/70.00
Jan – Mar 2006	500	Costless Collar	50.00/75.00
Jan – Mar 2006	1000	Costless Collar	50.00/82.80
Apr – Jun 2006	500	Costless Collar	40.00/71.25
Apr – Jun 2006	500	Costless Collar	50.00/70.00
Apr – Jun 2006	500	Costless Collar	50.00/75.70
Apr – Jun 2006	1000	Costless Collar	50.00/82.75
Apr – Jun 2006	500	Costless Collar	50.00/75.05
Jul – Sep 2006	500	Costless Collar	50.00/75.30
Jul – Sep 2006	1000	Costless Collar	50.00/82.05
Jul – Sep 2006	500	Costless Collar	50.00/76.05
Oct – Dec 2006	500	Costless Collar	50.00/75.03
Oct – Dec 2006	1000	Costless Collar	50.00/81.50
Oct – Dec 2006	500	Costless Collar	50.00/75.00
Jan – Mar 2007	500	Costless Collar	50.00/76.00
Apr – Jun 2007	500	Costless Collar	50.00/80.00

NATURAL GAS

Period	Volume (mmcf/day)	Type	AECO Price (Cdn$/mcf)
Jan – Mar 2006	10	Costless Collar	6.33/9.96
Jan – Mar 2006	10	Costless Collar	6.33/10.22
Jan – Mar 2006	5	Costless Collar	6.33/10.42
Jan – Mar 2006	10	Costless Collar	6.33/10.55
Jan – Mar 2006	5	Costless Collar	6.33/11.61
Jan – Mar 2006	5	Costless Collar	6.33/12.66
Jan – Mar 2006	5	Costless Collar	6.33/13.13
Jan – Mar 2006	5	Costless Collar	6.33/14.03
Jan – Mar 2006	5	Costless Collar	7.39/14.51
Jan – Mar 2006	10	Costless Collar	7.39/14.56
Jan – Mar 2006	5	Costless Collar	10.34/16.88
Jan – Mar 2006	5	Costless Collar	10.55/26.11
Jan – Mar 2006	5	Costless Collar	11.61/22.42
Apr – Jun 2006	5	Costless Collar	6.33/8.91
Apr – Jun 2006	10	Costless Collar	6.86/10.55
Apr – Jun 2006	5	Costless Collar	6.86/10.63
Apr – Jun 2006	5	Costless Collar	7.39/13.72
Apr – Jun 2006	5	Costless Collar	8.44/12.98
Apr – Jun 2006	5	Costless Collar	8.44/15.30

Period	Volume (mmcf/day)	Type	AECO Price (Cdn$/mcf)
Apr – Jun 2006	10	Costless Collar	8.44/16.62
Jul – Sep 2006	10	Costless Collar	6.86/10.55
Jul – Sep 2006	5	Costless Collar	6.86/10.68
Jul – Sep 2006	5	Costless Collar	7.39/13.56
Jul – Sep 2006	5	Costless Collar	8.44/13.98
Jul – Sep 2006	5	Costless Collar	8.44/15.72
Jul – Sep 2006	5	Costless Collar	8.44/15.83
Jul – Sep 2006	10	Costless Collar	8.44/16.30
Oct – Dec 2006	5	Costless Collar	6.86/11.92
Oct – Dec 2006	10	Costless Collar	6.86/12.66
Oct – Dec 2006	5	Costless Collar	7.39/15.83
Oct – Dec 2006	5	Costless Collar	8.44/15.83
Oct – Dec 2006	5	Costless Collar	8.44/17.94
Oct – Dec 2006	5	Costless Collar	8.44/18.99
Oct – Dec 2006	10	Costless Collar	8.44/19.25
Jan – Mar 2007	5	Costless Collar	8.44/18.46
Jan – Mar 2007	5	Costless Collar	8.44/21.10
Jan – Mar 2007	5	Costless Collar	8.44/21.21

In 2005, the financial impact of contracts settling in the year was a decrease in sales revenues of $44.3 million (2004 – $28.2 million decrease in sales revenue).

The mark-to-market value of the hedges in place as at December 31, 2005 is an $11.5 million loss of which $9.2 million is attributable to natural gas and $2.3 million is attributable to crude oil.

b) Fair Value of Financial Instruments

Financial instruments include cash, accounts receivable, accounts payable and accrued liabilities, accrued distributions to Unitholders and long-term debt. As at December 31, 2005, 2004, and 2003, the fair market value of these financial instruments, other than long-term debt, approximate their carrying value, due to the short-term maturity of these instruments. The fair value of long-term debt approximates its carrying value in all material respects, because the cost of borrowing approximates the market rate for similar borrowings.

18. Commitments and Contingencies

a) PrimeWest has lease commitments relating to office buildings. The estimated annual minimum operating lease rental payments for the buildings, after deducting sublease income will be $3.7 million in 2006, $3.5 million in 2007, $3.4 million in 2008 and $0.9 million in 2009.

b) As part of PrimeWest's internalization transaction which closed on November 6, 2002 PrimeWest agreed to issue 377,340 Exchangeable Shares to certain executive officers as a SERP. The SERP issued 94,340 Exchangeable Shares on each of November 6, 2004 and 2005 and will issue an additional 94,340 Exchangeable Shares on November 6, 2006 and 2007. For the twelve months ended December 31, 2005, $1.8 million was recorded in non-cash general and administrative expense related to the SERP.

c) PrimeWest has various pipeline transportation commitments that run through 2011. The estimated annual payments are $7.2 million in 2006, $3.2 million in 2007, $0.5 million in 2008, $0.3 million in 2009, $0.2 million in 2010 and $0.1 million in 2011.

d) PrimeWest is engaged in a number of matters of litigation, none of which could reasonably be expected to result in any material adverse consequence.

19. Prior Years' Comparative Numbers

Certain prior years' comparative numbers have been restated to conform to the current year's presentation.

20. Differences Between Canadian And United States Generally Accepted Accounting Principles

PrimeWest's financial statements are prepared in accordance with generally accepted accounting principles (GAAP) in Canada, which, in some respects, differ from those generally accepted in the United States (US GAAP). The following are those policies that result in significant measurement difference.

1. Property, Plant and Equipment

PrimeWest uses the ceiling test method set out in CICA Accounting Guideline 16 (AcG-16), "Oil and Gas Accounting – Full Costs". This guideline requires that cost centres be tested for recoverability using undiscounted future cash flows from Proved reserves, which are determined by using forward indexed prices. When the carrying amount of a cost centre is not recoverable, the cost centre must be written down to its fair value. Fair value is estimated using accepted present value techniques that incorporate risks and other uncertainties when determining expected cash flows.

In accordance with the full cost method of accounting under U.S. GAAP, the net carrying value is limited to a standardized measure of discounted future cash flows, before financing and general administrative costs. Where the amount of a ceiling test write down under Canadian GAAP differs from the amount of a write down under U.S. GAAP, the charge for depreciation and depletion under U.S. and Canadian GAAP will differ in subsequent years.

Under Canadian GAAP, depletion charges are calculated by reference to Proved reserves estimated using future prices and estimated future costs. Under U.S. GAAP, depletion charges are calculated by reference to Proved reserves using constant prices.

2. Asset Retirement Obligation

Effective January 1, 2004, PrimeWest changed its accounting policy with respect to accounting for asset retirement obligations. CICA section 3110 requires the fair value of asset retirement obligations be recorded when they are incurred rather than merely accumulated or accrued over the useful life of the respective asset. The change in accounting policy was recorded as an adjustment to accumulated income with retroactive restatement of prior period comparatives.

The change in accounting policy was consistent with the Trust's adoption of the Financial Accounting Standards Board (FAS) 143 Accounting for Asset Retirement Obligations, effective January 1, 2003. The new standard requires the recognition of the liability associated with the future site reclamation costs of the long-lived assets. The liability for future retirement obligations is recorded in the financial statements at the time the liability is incurred.

The asset retirement obligation is initially recorded at the estimated fair value as a long-term liability with a corresponding increase to property, plant and equipment. The depreciation of property, plant and equipment (PP&E) is allocated to expense on the unit-of-production basis.

The adoption of FAS 143 allows for the cumulative effect of the change in accounting policy to be booked as a transitional adjustment to net income with no restatement of prior period comparatives. At January 1, 2003, this resulted in an increase to the asset retirement obligation of $15.3 million, an increase to PP&E of $8.4 million in 2003, a $0.4 million decrease to net income after tax, a decrease in the site restoration provision of $6.2 million and a decrease to the future income tax liability of $0.3 million.

Implementation of this accounting standard did not affect the Trust's cash flow or liquidity.

3. Marketable Securities

PrimeWest follows the cost method of accounting for the investment in marketable securities as established by the CICA. Under this accounting policy, the investment is initially recorded at cost with the corresponding distributions received in excess of earnings recorded as a reduction to the carrying amount of the investment. Under U.S. GAAP, the marketable securities are considered held for trading and recorded on the balance sheet at fair value. The corresponding difference between the cost method and fair value is recorded in earnings in the current year and results in a Canadian/US GAAP difference.

4. Unitholders' Mezzanine Equity

PrimeWest accounts for all Trust Units and Exchangeable Shares outstanding as permanent equity presented as Net capital contributions under Unitholder's Equity on the balance sheet. The Trust Units are redeemable at the option of the Unitholder, and therefore must be valued at their redemption amount and presented as mezzanine equity in the consolidated balance sheet under U.S. GAAP. The redemption value of the Trust Units is based on the trading value of the Trust Units and the Trust Unit equivalent of the Exchangeable Shares at each balance sheet date. At December 31, 2005 and 2004, the Trust classified $2.8 billion and $1.6 billion from Unitholders' Equity, respectively, to mezzanine equity in accordance with U.S. GAAP. The Trust has also recognized a deficit of $1.6 billion for 2005 and $0.5 billion for 2004 resulting from eliminating the Unitholders' equity accounts of the Trust and replacing them with Unitholders' mezzanine equity at redemption value.

In 2004 and prior years, the Trust believed there were sufficient restrictions on redemptions to classify the trust units as permanent equity for U.S. GAAP purposes. Upon further review it was determined that the Trust Units should be accounted for as temporary equity for U.S. GAAP purposes as set out in the preceding paragraph. Prior year amounts have been restated.

5. Unit-Based Compensation

Effective January 1, 2005, PrimeWest adopted the fair value method of accounting for Unit Appreciation Rights (UARs) for Canadian GAAP purposes. In prior years, the intrinsic method had been used. For U.S. GAAP purposes, the intrinsic method of valuing unit-based compensation continues to be used in accordance with APB Opinion No. 25 "Accounting for Stock Issued to Employees". For U.S. GAAP purposes, the accounting policy change restatements recorded for Canadian GAAP purposes have been reversed and restatement of only the future income tax portion has been recorded. In addition, unit-based compensation expense computed in accordance with the intrinsic method is included as non-cash G&A expense in 2005 consistent with prior years.

If the fair value method of valuing unit-based compensation were used for U.S. GAAP purposes, reported earnings per share numbers would increase by $0.70 in 2005 ($0.09 in 2004; $0.24 in 2003).

RECENT ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT IMPLEMENTED

On December 15, 2004 FAS Statement No. 123R "Share-Based Payment" was issued. The standard mandates that a public entity measure the cost of equity-based service awards based on the fair value of the award at grant date. That cost will be recognized over the period during which an employee is required to provide service in exchange for the award or the requisite service period. No compensation cost is recognized for equity instruments for which employees do not render the requisite service. The public entity will initially measure the cost of the liability-based service awards based on its current fair value. The fair value of that award will be remeasured subsequently at each reporting date through the settlement date. Changes in fair value during the requisite service period will be recognized as compensation cost over that period. The Trust is currently assessing the impact of the pronouncement on the financial statements.

The following tables set out the significant differences in the consolidated financial statements using U.S. GAAP.

a) Consolidated Net Income

($ millions, except per Trust Unit amounts)	2005	2004	2003
Net income as reported	$ 207.5	$ 105.4	$ 102.7
Reverse restatement of unit-based compensation expense			
Non-cash G&A expense	-	(5.3)	(11.3)
Future income tax expense	-	3.3	4.5
Net income as published in prior years	$ 207.5	$ 103.4	$ 95.9
Record for U.S. GAAP purposes restatement of future income tax expense related to unit-based compensation	-	(3.3)	(4.5)
Adjustments			
Depletion and depreciation	17.8	(4.2)	35.4
FAS 115 adjustment	(22.6)	22.6	-
FAS 133 adjustment	-	5.4	6.1
Non-cash G&A expense related to unit-based compensation (intrinsic method)	(56.3)	-	-
Non-cash G&A expense related to unit-based compensation (fair value method)	3.6	-	-
Future income tax expense	(6.0)	(4.3)	(42.3)
Adjusted net income before change in accounting policy	144.0	119.6	90.6
Cumulative effect of change in accounting policy, net of tax of $0.3 million	-	-	(0.4)
Adjusted net income	$ 144.0	$ 119.6	$ 90.2
Net income per Trust Unit			
U.S. GAAP – Basic	$ 1.90	$ 2.01	$ 1.96
– Diluted	$ 1.88	$ 1.99	$ 1.95
Cumulative effect of change in accounting policy per Trust Unit			
U.S. GAAP – Basic	$ -	$ -	$ 0.01
– Diluted	$ -	$ -	$ 0.01

b) Consolidated Unitholders' Equity

($ millions, except per Trust Unit amounts)	2005	2004
Unitholders' equity as reported	$ 1,359.9	$ 1,180.4
Reverse restatement resulting from change in accounting method of unit-based compensation recorded for Canadian GAAP purposes:		
Capital contributions	7.9	7.9
Accumulated income	(7.1)	(7.1)
Contributed surplus	(6.4)	(6.4)
LTIP equity	20.1	20.1
Unitholders' equity as reported before restatement	$ 1,374.4	$ 1,194.9
Record restatement of future income tax expense for U.S. GAAP	(14.5)	(14.5)
Adjustments related to income		
Depletion and depreciation	(252.5)	(270.3)
FAS 115 adjustment	-	22.6
Future income tax recovery	113.2	119.2
Adjustments related to presentation of mezzanine equity:		
Net capital contributions	(2,313.0)	(2,049.9)
Capital issued but not distributed	(3.6)	(3.3)
Convertible Unsecured Subordinated Debentures	(1.8)	(8.1)
Long-term incentive plan equity	(64.3)	(20.1)
US GAAP accumulated income	(90.2)	53.8
Accumulated cash distributions	1,244.3	967.7
Accumulated dividends	8.0	8.0
Deficit	(1,568.4)	(529.6)
Unitholders' equity	$ (1,568.4)	$ (529.6)

c) Consolidated Balance Sheets

		2005	
($ millions)	Note	CDN GAAP	US GAAP
Property, plant and equipment (net)	1	$ 1,859.9	$ 1,668.6
Marketable securities	3	-	-
Future income tax liability	1,2	214.8	162.7
Mezzanine equity	4	-	2,789.1
Net capital contributions	4,5	2,294.3	-
Convertible Unsecured Subordinated Debentures	4	1.8	-
Capital issued but not distributed	4	3.6	-
Contributed surplus	4,5	8.7	-
Accumulated income (deficit)	1,2,4,5	303.8	(1,568.4)
Accumulated cash distributions	4	(1,244.3)	-
Accumulated dividends	4	(8.0)	-

		2004	
($ millions)	Note	CDN GAAP	US GAAP (restated – see note 4)
Property, plant and equipment (net)	1	$ 1,908.6	$ 1,699.4
Marketable securities	3	68.6	91.2
Future income tax liability	1,2	225.7	167.7
Mezzanine equity	4	-	1,581.5
Net capital contributions	4,5	2,042.0	-
Convertible Unsecured Subordinated Debentures	4	8.1	-
Capital issued but not distributed	4	3.3	-
Contributed surplus	4,5	6.4	-
Accumulated income (deficit)	1,2,4,5	96.3	(529.6)
Accumulated cash distributions	4	(967.7)	-
Accumulated dividends	4	(8.0)	-

d) Consolidated Cash Flows

The consolidated statements of cash flows prepared in accordance with Canadian GAAP conform in all material respects with U.S. GAAP, except that Canadian GAAP allows for the presentation of operating cash flow before changes in non-cash working capital items in the consolidated statement of cash flows. This total cannot be presented under U.S. GAAP.

FAS 69 SUPPLEMENTAL RESERVE INFORMATION (UNAUDITED)

The following data supplements oil and natural gas disclosure in the Trust's annual report and is provided in accordance with the provisions of FAS 69.

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of "Proved" and "Proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale, which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Trust's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Trust's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2005, no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of Proved or Proved developed reserves as of that date.

Results of Oil and Gas Operations ($ millions)	2005	2004	2003
Revenues	$ 597.1	$ 394.6	$ 329.9
Expenses			
Production costs	117.0	88.9	79.4
Depreciation, depletion and amortization	212.4	201.5	170.3
Accretion	2.5	2.0	1.2
Tax recovery	(12.4)	(30.0)	(39.9)
	319.5	262.4	211.0
Results of operations from oil and natural gas operations	$ 277.6	$ 132.2	$ 118.9

Costs Incurred ($ millions)	2005	2004	2003
Property acquisition costs			
Proved properties	$ 2.7	$ 770.5	$ 202.4
Unproved properties	17.6	52.1	34.0
Exploration costs	8.7	16.0	5.7
Development costs	165.4	123.6	101.5
	$ 194.4	$ 962.2	$ 343.6

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and natural gas properties.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and natural gas, along with an allocation of overhead.

Capitalized Costs ($ millions)	2005	2004	2003
Proved properties	$ 2,852.6	$ 2,599.1	$ 2,189.0
Unproved properties	88.0	103.9	36.0
	2,940.6	2,703.0	2,225.0
Less related accumulated depreciation, depletion and amortization	(1,280.2)	(1,010.0)	(1,186.2)
	$ 1,660.4	$ 1,693.0	$ 1,038.8

PROVED OIL AND NATURAL GAS RESERVE QUANTITIES

	2005		2004		2003	
	Crude Oil and Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Crude Oil and Natural Gas Liquids (mbbls)	Natural Gas (mmcf)	Crude Oil and Natural Gas Liquids (mbbls)	Natural Gas (mmcf)
Opening balance	27,799	422,227	25,643	272,897	25,989	279,106
Revision of previous estimates	891	992	(806)	2,640	225	(33,640)
Purchase of reserves in place	-	148	6,940	180,914	1,640	50,389
Sale of reserves in place	(72)	(1,913)	(2,120)	(8,027)	(28)	(803)
Discoveries and extensions	1,400	38,088	791	16,018	941	14,742
Production	(3,114)	(49,535)	(2,649)	(42,215)	(3,124)	(36,897)
Closing balance	26,904	410,007	27,799	422,227	25,643	272,897

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED RESERVES

The standardized measure for calculating the present value of future net cash flows from Proved oil and natural gas reserves is based on current costs and prices and a ten percent discount factor as prescribed by FAS 69.

Accordingly, the estimated future net cash inflows were computed by applying prevailing selling prices at year end to the estimated future production of Proved reserves. Estimated future expenditures are based on future development costs.

Although these calculations have been prepared according to the standards described above, it should be emphasized that due to the number of assumptions and estimates required in the calculation, the amounts are not indicative of the amount of net revenue that the Trust expects to receive in future years. They are also not indicative of the current value or future earnings that may be realized from the production of Proved reserves, nor should it be assumed that they represent the fair market value of the reserves or of the oil and natural gas properties.

Although the calculations are based on existing economic conditions at each year end, such economic conditions have changed and may continue to change significantly due to events such as the continuing changes in the natural gas market and changes in government policies and regulations. While the calculations are based on the Trust's understanding of the established FASB guidelines, there are numerous other equally valid assumptions under which these estimates could be made that would produce significantly different results.

Standardized Measure ($ millions)		2005		2004		2003
Future cash inflows	$	6,072.0	$	4,187.1	$	2,631.1
Future production costs		(1,371.3)		(1,186.6)		(804.9)
Future development costs		(123.1)		(72.0)		(69.4)
Other related future costs		(40.7)		(37.1)		(42.1)
Future net cash flows		4,536.9		2,891.4		1,714.7
Discount at 10%		(1,999.1)		(1,242.7)		(721.6)
Standardized measure of discounted future net cash flow related to Proved Reserves	$	2,537.8	$	1,648.7	$	993.1

Summary of Changes in the Standardized Measure During The Year ($ millions)		2005		2004		2003
Sales of oil and natural gas produced, net of production costs	$	(459.9)	$	(312.2)	$	(255.0)
Net change in sales and transfer prices, net of development and production costs		987.1		144.4		(106.2)
Sales of reserves in place		(10.4)		(54.4)		(2.3)
Purchases of reserves in place		0.5		630.4		156.4
Extensions, discoveries and improved recovery, less related costs		223.0		106.7		48.5
Changes in timing of future net cash flows and other		(12.5)		37.1		(60.6)
Revisions of previous quantity estimates		(3.6)		4.3		(58.5)
Accretion of discount		164.9		99.3		115.5
Net change		889.1		655.6		(162.2)
Balance at beginning of year		1,648.7		993.1		1,155.3
Balance at end of year	$	2,537.8	$	1,648.7	$	993.1

Trading Performance

For the Quarter Ended	Dec 31/05	Sep 30/05	Jun 30/05	Mar 31/05	Dec 31/04
TSX Trust Unit Prices ($ per Trust Unit)					
High	$ 37.68	$ 36.42	$ 31.68	$ 32.00	$ 28.33
Low	$ 30.55	$ 30.86	$ 28.35	$ 26.15	$ 25.06
Close	$ 35.90	$ 36.40	$ 30.66	$ 28.99	$ 26.62
Average daily traded volume	199,849	183,469	202,225	269,714	255,944

For the quarter ended	Dec 31/05	Sep 30/05	Jun 30/05	Mar 31/05	Dec 31/04
NYSE Trust Unit Prices (US$ per Trust Unit)					
High	$ 32.57	$ 31.37	$ 25.59	$ 26.60	$ 22.98
Low	$ 25.71	$ 25.15	$ 22.50	$ 21.30	$ 20.85
Close	$ 30.92	$ 31.33	$ 25.05	$ 23.96	$ 22.18
Average daily traded volume	480,603	445,338	377,264	536,170	542,483
Number of Trust Units outstanding including Exchangeable Shares (millions of Trust Units)	80.4	79.1	77.2	72.9	70.5
Distribution paid per Trust Unit	$ 0.96	$ 0.90	$ 0.90	$ 0.90	$ 0.90

TOTAL COMPOUND ANNUAL RETURN (%)(1)

	PrimeWest	TSX Oil & Gas Index	TSX S&P	S&P 500 Cdn$	S&P 500 US$	S&P/TSX CDN Energy Trust Index
Five year	19.0	25.8	6.7	(4.5)	0.5	30.7
Three year	28.6	38.5	21.7	3.7	13.2	41.8
One year	51.4	63.7	24.3	1.5	4.9	49.5

(1) Total return = Unit price plus distributions re-invested.

Five Year Financial Summary

($ millions, except per BOE and per Trust Unit amounts)	2005	2004	2003	2002	2001
Cash flow from operations	$ 414.1	$ 266.8	$ 216.6	$ 170.9	$ 214.5
Per Trust Unit	5.16	4.33	4.67	4.96	8.27
Per BOE	28.11	20.49	17.82	15.51	19.74
Net revenues	604.4	402.8	338.2	270.6	311.5
Per Trust Unit	7.32	6.38	7.30	7.85	12.00
Per BOE	41.04	30.93	27.82	24.55	28.66
Operating expenses	117.0	88.9	79.4	60.8	59.0
Per Trust Unit	1.42	1.41	1.71	1.76	2.27
Per BOE	7.94	6.83	6.53	5.52	5.42
Operating margin	464.6	305.6	250.5	203.5	247.6
Per Trust Unit	5.63	4.84	5.41	5.90	9.54
Per BOE	31.54	23.47	20.61	18.46	22.78
Cash G&A	22.9	19.0	14.5	11.3	10.4
Per Trust Unit	0.28	0.30	0.31	0.33	0.40
Per BOE	1.56	1.46	1.20	1.02	0.96
Interest expense	28.3	20.6	15.1	10.8	13.8
Per Trust Unit	0.34	0.33	0.32	0.32	0.53
Per BOE	1.92	1.58	1.24	0.98	1.27
Development capital expenditures	185.6	125.1	104.5	64.2	83.9
Acquisitions net of dispositions	(17.9)	707.9	228.6	56.5	744.5
Working capital surplus/(deficit) [(1)]	30.5	104.3	(5.8)	(0.7)	(29.4)
Total assets	2,131.9	2,240.9	1,690.5	1,511.5	1,530.0
Net asset value	2,565.1	1,541.2	692.4	727.9	755.2
Per Trust Unit	30.64	19.15	13.74	18.52	22.82
Total capitalization (including debt)	3,208.4	2,429.7	1,636.6	1,072.5	1,080.7
Debt Analysis					
Long-term debt, including working capital	323.7	552.0	255.9	225.7	224.4
Debt to annual cash flow ratio	0.8	1.70	1.18	1.32	1.05
Debt to equity ratio	19.2	31.6	25.1	26.6	26.2
Interest coverage ratio	15.6	14.2	15.9	16.9	16.5
Average cost of debt	5.2%	4.8%	4.7%	4.6%	5.4%
Net debt per Trust Unit	3.97	7.77	5.07	5.75	6.78
Tax Pools (Consolidated)					
Canadian Oil And Gas Property Expense (COGPE)	825.0	879.0	426.0	425.0	424.0
Canadian Exploration Expense (CEE)	9.8	79.8	61.5	–	23.7
Canadian Development Expense (CDE)	156.0	109.5	60.9	41.2	11.1
Capital Cost Allowance (CCA)	325.1	281.8	126.0	108.0	101.2
Losses Available For Carry Forward	3.6	3.6	–	11.8	24.8
Unit issue expenses	24.9	37.5	17.3	12.5	12.2

(1) Excludes derivative liabilities and assets and future income tax assets

Five Year Operating Summary

	2005	2004	2003	2002	2001
Average Daily Production					
Natural gas (mmcf/day)	178.2	145.1	134.1	113.5	104.8
Crude oil (bbls/day)	6,861	8,282	8,116	9,239	10,033
Natural gas liquids (bbls/day)	3,797	3,107	2,855	2,030	2,273
Total (BOE/day)	40,351	35,578	33,316	30,189	29,774
Average Selling Prices (Cdn$)					
Natural gas ($/mcf)	$ 8.43	$ 6.61	$ 6.05	$ 4.55	$ 6.16
Crude oil ($/bbl)	49.05	36.83	33.94	33.53	32.21
Natural gas liquids ($/bbl)	55.92	43.69	35.34	26.56	30.96
Total ($/BOE)	$ 50.81	$ 39.35	$ 35.63	$ 29.16	$ 34.80
Benchmark Prices					
Monthly AECO Spot (Cdn$/mcf)	$ 8.04	$ 6.79	$ 6.70	$ 4.07	$ 6.30
W.T.I. (US$/bbl)	$ 56.56	$ 41.40	$ 31.04	$ 26.08	$ 25.97
Operating Margin ($/BOE)					
Revenues	$ 51.21	$ 39.50	$ 35.52	$ 29.11	$ 34.93
Royalties	(11.73)	(9.20)	(8.38)	(5.13)	(6.73)
Operating expenses	(7.94)	(6.83)	(6.53)	(5.52)	(5.42)
Operating margin ($/BOE)	$ 31.54	$ 23.47	$ 20.61	$ 18.46	$ 22.78
Reserves Summary [1,2]					
Crude oil (mmbbls)	23.6	23.9	22.9	24.5	28.5
Natural gas liquids (mmbbls)	18.1	18.3	11.9	10.2	9.5
Natural gas (bcf)	677.3	677.9	432.2	418.5	413.7
Total BOE (mmBOE)	154.6	155.2	106.8	104.4	107.0
Net Asset Value ($ millions, except per Trust Unit amounts)					
Reserves (10% discount)[3]	$ 2,684.0	$ 1,714.4	$ 904.6	$ 923.0	$ 872.6
Market value of Viking Energy Royalty Trust Units	-	91.0	-	-	-
Hedging mark-to-market	(11.5)	0.1	(0.5)	(13.6)	50.5
Unproved lands and reclamation fund	160.5	114.2	44.2	44.2	56.5
Long-term debt and working capital	(267.9)	(378.5)	(255.9)	(225.7)	(224.4)
Total net asset value	$ 2,565.1	$ 1,541.2	$ 692.4	$ 727.9	$ 755.2
Per Trust Unit – Diluted	$ 30.64	$ 19.15	$ 13.74	$ 18.52	$ 22.82
Reserve Life Index[2] (years)	11.0	10.3	9.8	9.5	10.0

(1) Company Interest reserves.

(2) Total Proved plus Probable used for 2005, 2004 and 2003, all prior years used Established.

(3) Company Interest Proved plus Probable reserves.

FIVE YEAR TRADING, PERFORMANCE AND DISTRIBUTION SUMMARY

	2005 Q1	2005 Q2	2005 Q3	2005 Q4	2005 Full Year	2004	2003	2002	2001
Units Issued and Outstanding									
Period end (000s)	72,238	76,520	78,412	79,666	79,666	69,886	48,752	37,005	31,492
Exchangeable Shares Issued and Outstanding									
Period end (000s)	1,226	1,221	1,221	1,219	1,219	1,294	3,041	5,179	4,068
Converted to Trust Units	637	654	671	688	688	652	1,347	1,940	1,294
Exchange ratio at period end	0.51956	0.53538	0.54957	0.56399	0.56399	0.50408	0.44302	0.37454	0.31799
TSX Unit Price ($)									
High	$ 32.00	$ 31.68	$ 36.42	$ 37.68	$ 37.68	$ 28.35	$ 28.15	$ 29.56	$ 42.16
Low	$ 26.15	$ 28.35	$ 30.86	$ 30.55	$ 26.15	$ 22.18	$ 23.40	$ 23.60	$ 23.80
Close	$ 28.99	$ 30.66	$ 36.40	$ 35.90	$ 35.90	$ 26.62	$ 27.56	$ 25.40	$ 25.44
Average daily traded volume	269,714	202,225	183,469	199,849	213,656	233,579	192,678	123,455	156,122
Market capitalization at end of period ($ millions)					2,885	1,878	1,381	989	834
Total return for Canadian Unitholders during period					51.4%	9.7%	28.0%	19.5%	(5.8%)
NYSE Unit Price (US$)									
High	$ 26.60	$ 25.59	$ 31.37	$ 32.57	$ 32.57	$ 22.98	$ 21.48	$ 16.69	n/a
Low	$ 21.30	$ 22.50	$ 25.15	$ 25.71	$ 21.30	$ 16.00	$ 15.97	$ 15.62	n/a
Close	$ 23.96	$ 25.05	$ 31.33	$ 30.92	$ 30.92	$ 22.18	$ 21.27	$ 16.16	n/a
Average daily traded volume	536,170	377,264	445,338	480,603	458,853	402,694	169,269	39,276	n/a
Total return for U.S. Unitholders during period					56.6%	18.5%	55.3%	n/a	n/a
Distribution Summary ($ millions, except per Trust Unit amounts)									
Cash distributed to Unitholders	$ 63.8	$ 66.5	$ 70.1	$ 76.2	$ 276.6	$ 196.1	$ 192.6	$ 158.0	$ 234.4
Per Trust Unit	$ 0.90	$ 0.90	$ 0.90	$ 0.96	$ 3.66	$ 3.30	$ 4.32	$ 4.80	$ 9.84
Percentage paid out	80%	70%	66%	58%	67%	74%	89%	92%	109%
Cumulative cash distributions	$ 1,031.5	$ 1,098.0	$ 1,168.1	$ 1,244.3	$ 1,244.3	$ 967.7	$ 771.5	$ 578.9	$ 420.9
Per Trust Unit	$ 44.44	$ 45.34	$ 46.24	$ 47.20	$ 47.20	$ 43.54	$ 40.24	$ 35.92	$ 31.12

Distribution History ($ per Trust Unit)

Funds paid in:	2005 Cdn$	2005 US$	2004 Cdn$	2004 US$	2003 Cdn$	2003 US$	2002 Cdn$	2002 US$	2001 Cdn$	2001 US$
Q1	$ 0.90	$ 0.74	$ 0.82	$ 0.62	1.20	$ 0.81	$ 1.20	$ 0.75	$ 2.40	$ 1.56
Q2	0.90	0.72	0.75	0.55	1.20	0.87	1.20	0.77	2.56	1.66
Q3	0.90	0.76	0.83	0.64	0.96	0.70	1.20	0.77	2.64	1.71
Q4	0.96	0.82	0.90	0.74	0.96	0.73	1.20	0.76	2.04	1.31
Total for year	$ 3.66	$ 3.04	$ 3.30	$ 2.55	4.32	$ 3.12	$ 4.80	$ 3.05	$ 9.64	$ 6.24
% Tax-deferred	25%	18.75%	45%	55%	42%	100%	45%	100%	33%	n/a
Exchange Rate (US$/Cdn$)	$ 0.829		$ 0.769		$ 0.715		$ 0.637		$ 0.646	

Three Year Distribution History

2003	Distribution per Trust Unit (1) Cdn$	Distribution Per Trust Unit (1) US$
January	$ 0.40	$ 0.2600
February	0.40	0.2700
March	0.40	0.2800
April	0.40	0.2890
May	0.40	0.2990
June	0.40	0.2870
July	0.32	0.2300
August	0.32	0.2300
September	0.32	0.2400
October	0.32	0.2460
November	0.32	0.2400
December	0.32	0.2465
Total 2003	$ 4.32	$ 3.118
2004		
January	0.32	0.2431
February	0.25	0.1870
March	0.25	0.1860
April	0.25	0.1798
May	0.25	0.1830
June	0.25	0.1887
July	0.25	0.1910
August	0.275	0.2120
September	0.30	0.2395
October	0.30	0.2499
November	0.30	0.2450
December	0.30	0.2468
Total 2004	$ 3.295	$ 2.552
2005		
January	0.30	0.2468
February	0.30	0.2438
March	0.30	0.2486
April	0.30	0.2406
May	0.30	0.2370
June	0.30	0.2424
July	0.30	0.2458
August	0.30	0.2501
September	0.30	0.2532
October	0.30	0.2531
November	0.30	0.2516
December	0.36	0.2587
Total 2005	$ 3.66	$ 2.9717

(1) Monthly information refers to the month in which the distributions are declared with payment being made on or about the 15th day of the following month.

Income Tax Considerations

This commentary regarding income taxes is of a general nature only and is not intended to be legal or tax advice applicable to a specific Unitholder. Unitholders and prospective investors are, therefore, encouraged to consult a tax advisor with regard to their specific circumstances.

For Canadian Unitholders

PrimeWest is regarded as a mutual fund trust for purposes of the Canadian Income Tax Act. Each year, an income tax return is filed by the Trust with the taxable income allocated to, and taxable in the hands of Unitholders. Distributions paid by the Trust have two components: (1) a tax-deferred return of capital (i.e. a repayment of a portion of a Unitholders' investment) and (2) a taxable return on capital (i.e. other income).

Each year, the return on capital or taxable portion of the distribution is reported on the Trust's T3 return. It is then allocated to each Unitholder who received distributions in the taxation year on the T3 supplementary forms, which are mailed in later February or early March of the following calendar year. Registered Unitholders receive a T3 from the Trust's transfer agent, Computershare Trust Company of Canada, while Unitholders who hold their units beneficially will receive a T3 from their bank or brokerage firm. The T3 form will indicate the taxable portion, or other income, as it is regarded under Canadian tax law in box 26 and the return of capital portion in box 42. The other income component is taxed on the same basis as interest income. The tax-deferred return of capital portion of the distribution should be treated as an adjustment to the cost base (ACB) of the Units. On disposition, the cost base should be reduced by the accumulated value of returned capital, resulting in a capital gain or loss for tax purposes.

For 2005, 25% of the distributions paid to Canadian residents were deemed a tax-deferred return of capital, and 75% was deemed taxable as other income. For the tax year 2006, PrimeWest's distributions payable to Canadian residents are estimated to be 80% taxable and 20% a tax-deferred return of capital.

For American and Other Non-Resident Unitholders

Investors who do not qualify as residents of Canada for income tax purposes should seek advice from a qualified tax advisor in their country of residence regarding the tax treatment of the distributions paid by PrimeWest. Monthly distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the Canadian Income Tax Act. However, the level of withholding tax may be reduced in accordance with reciprocal tax treaties.

In the case of the Canada-United States Tax Convention, U.S. residents are subject to a 15% withholding tax on the distributions paid by PrimeWest. For distributions paid during tax years 2004 and prior, the 15% withholding tax is refundable for that portion of the distributions deemed to be a tax-deferred return of capital. U.S. residents may apply to the Canada Revenue Agency (CRA) of the Government of Canada for this refund no later than two years after the calendar year in which the distributions were paid. Application for refund may be made by filing CRA Form NR7-R "Application for Refund of Non-Resident Tax", which can be obtained by contacting the International Tax Services Office of the CRA at 1-800-267-5177 or on the internet at www.cra.gc.ca. U.S. investors are cautioned that the administrative protocol required to apply for the refund is burdensome, and they will require the assistance of their broker or tax advisor.

Alternatively, U.S. Unitholders may elect to claim a portion of the Canadian tax withheld on distributions paid during 2005 as a deduction against income, or, subject to certain restrictions, as a credit against their U.S. tax liability. U.S. Unitholders wishing to claim a foreign tax credit must complete IRS Form 1116, "Foreign Tax Credit" as an attachment to the Form 1040.

Due to differences in the income tax code of the United States, certain deductions not available in Canada are available in the United States and could result in differences in tax treatment of the distributions for U.S. Unitholders compared to those in Canada. For Unitholders resident in the United States, the taxability of distributions is derived using U.S. tax rules, which permit the deduction of Crown royalties and accounting-based depletion. In the case of a U.S. Unitholder, the taxable portion of the monthly distribution is determined based upon current and accumulated earnings in accordance with the IRS tax code. The currently taxable portion is regarded as a foreign issuer "qualified dividend" under the terms of the Jobs and Growth Reconciliation Act of 2003 (P.L. 108-27, 117 Stat.752) for tax reporting purposes and registered U.S. Unitholders should receive a CRA Form NR-4 from the Trust's transfer agent, Computershare Trust Company of Canada. U.S. Unitholders who hold their Units beneficially should receive an IRS Form 1099-DIV or similar document from their bank or brokerage firm. As a result of the foregoing rules, in the case of a U.S. resident, 81.25% of the distributions paid by PrimeWest during 2005 should be treated as a "qualified dividend" with the remaining 18.75% treated as a tax-deferred return of capital. The tax-deferred return of capital portion of the distribution should be treated as an adjustment to the cost base (ACB) of the Units. The original cost of the Units should be reduced by this accumulated amount when computing gains or losses at the time of disposition, at which time this should be reported as a capital gain or loss.

Premium Distribution, Distribution Reinvestment and Optional Trust Unit Purchase Plan

PrimeWest offers a number of attractive and economical options for Unitholders to maximize their investment in PrimeWest, including a Premium Distribution (PREP), Conventional Distribution Reinvestment (DRIP) and Optional Trust Unit Purchase Plan (OTUPP). Investors are able to participate in all of these plans without paying fees, including brokerage commissions.

Canadian Unitholders

The Premium Distribution (PREP), Distribution Reinvestment (DRIP) and Optional Trust Unit Purchase Plans (OTUPP) provide eligible holders of Trust Units that are resident in Canada the opportunity to either receive a premium cash payment in lieu of the cash distribution declared payable by PrimeWest or accumulate additional Trust Units at a 5% discount to the weighted average market price. Participants that are resident in Canada may also purchase additional Trust Units at the same 5% discount by investing additional sums within the limits and subject to the terms of the Plan.

The PREP enables Canadian Unitholders to receive a 2% cash premium on the monthly distribution they receive. The more conventional DRIP allows eligible Canadian Unitholders to reinvest distribution payments into Trust Units, acquired at a 5% discount to the volume weighted average market price.

Additional Trust Units may be purchased by eligible Canadian Unitholders through the OTUPP in minimum amounts of $100 per remittance up to a maximum amount of $100,000 per calendar year, at a 5% discount to the volume weighted average market price. The number of Units available under the OTUPP is limited by the TSX to a maximum of 2% of the total Trust Units outstanding at the end of the previous fiscal year.

Most larger banks, trust companies and brokerage firms will allow investors to participate in these programs, but many of the smaller firms do not. Please contact the bank, trust company or brokerage firm that holds your account to determine if they permit participation in these Plans. If you are unable to participate as a beneficial holder, you will need to hold the Units directly as a registered Unitholder or transfer the Units to a financial institution that permits participation.

United States Unitholders

The DRIP plan is now available to Unitholders resident in the United States and provides the opportunity to accumulate additional Trust Units at a 5% discount to the Average Market Price. Unitholders that are resident in the United States are not eligible to receive the premium cash payment under the PREP or to make optional cash payments under the OTUPP to purchase additional Trust Units pursuant to the Plan.

Please contact the brokerage firm that holds your account to determine if they permit participation in the DRIP. If you are unable to participate as a beneficial holder, you will need to hold the Units directly as a registered Unitholder or transfer the Units to a financial institution that permits participation.

Additional Information

We invite you to participate in these programs by completing the enrollment form on the PrimeWest website at www.primewestenergy.com. If you hold your units with a bank or brokerage firm, you will need to inform the firm directly of your interest in enrolling in the program. Additional information regarding the PREP, DRIP, and OTUPP can be obtained by contacting the Computershare Trust Company of Canada toll-free at 1-800-564-6253, or the Investor Relations group at PrimeWest toll-free at 1-877-968-7878, or via e-mail at investor@primewestenergy.com.

Definitions

AECO

Refers to a pricing point for gas produced in Western Canada located at a gas storage facility adjacent to the TransCanada Pipelines' mainline near the Alberta-Saskatchewan border.

ARTC

Means the Alberta royalty tax credit.

Cash Distribution Date

The date Distributable Income is paid to Unitholders, currently being on or about the 15th of each month, or the earlier business day if applicable, following any record date.

Circular

Refers to the Trust's Management Proxy Circular, dated March 15, 2006.

Company Interest

Refers to, in relation to PrimeWest's interest in production or Reserves, its working interest (operating or non operating) share before deduction of royalties and including royalty interests of PrimeWest and the Trust.

Credit Facility

Refers, collectively, to certain credit facilities provided by a syndicate of Canadian chartered banks and term debt provided by certain institutional investors, together offering a maximum aggregate borrowing capability of $625 million.

Distributable Income

Refers to all amounts received by the Trust in respect of the Royalty, ARTC, the gross overriding royalties held by the Trust direct and other income, less certain expenses and other deductions.

EDGAR

Means the Electronic Data Gathering, Analysis and Retrieval System on which submissions by companies and others required by law to file forms with the U.S. Securities and Exchange Commission are filed and accessible at www.sec.gov.

Forecast Prices and Costs

Refers to future prices and costs that are generally accepted as being a reasonable outlook for the future; or fixed or presently determinable future prices or costs to which PrimeWest is legally bound by a contractual or other obligation to supply a physical product.

GAAP

Means Generally Accepted Accounting Principles.

General and Administrative Costs

The amount in aggregate representing all expenditures and costs incurred by or in respect of PrimeWest in the management and administration of PrimeWest.

GLJ

Means GLJ Petroleum Consultants, Ltd.

GLJ Report

Means the reserve report dated January 23, 2006, prepared by GLJ, evaluating the light and medium oil, heavy oil and associated and non-associated gas reserves attributable to properties owned by the Trust as at December 31, 2005.

Gross

Refers to the Trust's "company gross reserves", which are PrimeWest's working interest (operated or non operated) share before deduction of royalties and without including any royalty interests of PrimeWest or the Trust; or in relation to wells, the total number of wells in which PrimeWest has an interest; or in relation to properties, the total area of properties in which PrimeWest has an interest.

Net

Refers to PrimeWest's interest in production or reserves, PrimeWest's working interest (operated or non operated) share after deduction of royalty obligations, plus the royalty interests of PrimeWest and the Trust in production or reserves; or in relation to PrimeWest's interest in wells, the number of wells obtained by aggregating PrimeWest's working interest in each of its Gross wells; or in relation to PrimeWest's interest in a property, the total area in which PrimeWest has an interest multiplied by its working interest.

NI 51-101

Means National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Commissions.

Probable Reserves

Those additional reserves that are less certain to be recovered than Proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves. In addition, the level of certainty targeted by the reporting company should result in at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

Production

Refers to recovering, gathering, treating, field or plant processing and field storage of oil and natural gas.

Production Costs

Costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other cost of operating and maintaining those wells and related equipment and facilities. Lifting costs become part of the cost of oil and natural gas produced.

Proved Reserves

Reserves that can be estimated with a high degree of certainty to be recoverable. The reporting company must believe that there is at least a 90% probability that the actual remaining quantities recovered will equal or exceed those estimated Proved reserves.

Record Date

The date by which a Unitholder must officially own the Trust Units in order to be entitled to receive a distribution.

Reserve Life Index

Is calculated by dividing the quantity of reserves by the total production of oil, natural gas and natural gas liquids during the year.

SEDAR

Refers to the System for Electronic Document Analysis and Retrieval established by the Canadian Securities Administrators as the system used for electronically filing most securities related information with the Canadian securities regulatory authorities and is accessible at www.sedar.com.

Standard and Poors (S&P)

Refers to Standard and Poors, a division of the McGraw-Hill Companies, Inc.

Trust Units

Refers to the units of the Trust, each unit representing an equal undivided beneficial interest in the Trust.

Trustee

Refers to Computershare Trust Company of Canada, or its successor, as trustee of the Trust.

Undeveloped Reserves

Refers to those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of Production. They must fully meet the requirements of the Reserves classification (Proved, Probable or Possible) to which they are assigned.

Unproved Properties

A property or part of a property to which no reserves have been specifically attributed.

Well Abandonment Costs

The costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

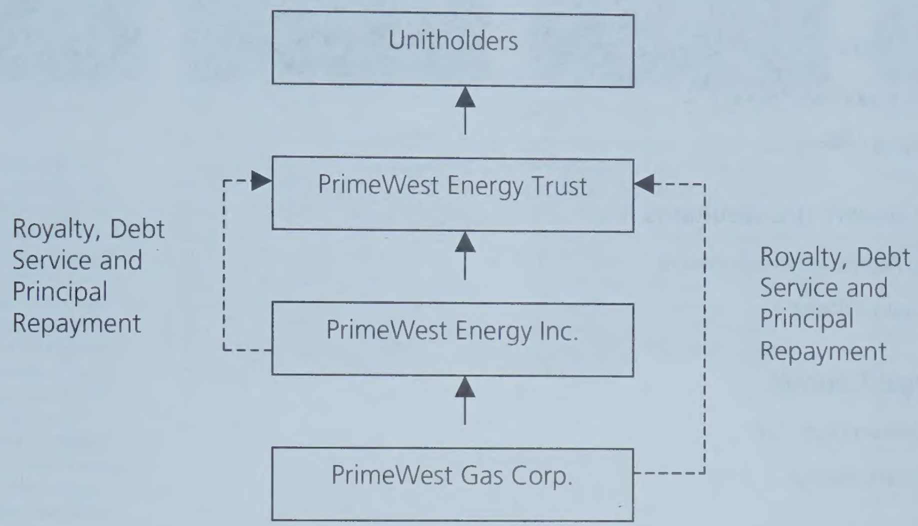
West Texas Intermediate

A high-quality grade of crude oil produced in West Texas whose price is most commonly used as a benchmark for crude oil pricing internationally.

Refer to PrimeWest's Renewal Annual Information Form for an explanation of additional defined terms used in this annual report.

PRIMEWEST STRUCTURE

The following diagram represents the current structure of the Trust and shows the flow of funds from the oil and natural gas properties owned, directly or indirectly, by PrimeWest and the gross overriding royalties owned directly by the Trust, as well as the flow of funds to PrimeWest and from the Trust to Unitholders.



Effective January 1, 2006, PrimeWest Gas Corp. amalgamated into PrimeWest Energy Inc.

Notes:

(1) The Trust also directly owns certain gross overriding royalty interests.

(2) PrimeWest, directly and indirectly through its subsidiaries, including PrimeWest Gas, actively manages its oil and natural gas properties to maximize cash flow and reserve value.

The principal undertaking of the Trust is to acquire and hold, directly and indirectly, interests in oil and natural gas properties. One of the Trust's primary assets is the Royalty granted by PrimeWest and PrimeWest Gas pursuant to the Royalty Agreement. The Royalty entitles the Trust to receive 99% of the net cash flow generated by the oil and natural gas interests held from time-to-time by PrimeWest, after certain costs and deductions. The balance of such net cash flow may be retained by PrimeWest to fund its working capital and other business and operating requirements, or may be passed on to the Trust to support distributions to Unitholders. The Distributable Income resulting from the Royalty and other amounts received by the Trust is then distributed monthly to Unitholders.

Corporate Information

Registrar and Transfer Agent

Computershare Trust Company of Canada

Toll-free: 1-800-564-6253

Auditors

PricewaterhouseCoopers, LLP

Calgary, Alberta

Engineering Consultants

GLJ Petroleum Consultants Ltd.

Calgary, Alberta

Legal Counsel

Stikeman Elliott, LLP

Calgary, Alberta

Trust Units

The Toronto Stock Exchange: PWI.UN

The New York Stock Exchange: PWI

Exchangeable Shares

The Toronto Stock Exchange: PWX

Convertible Debentures

The Toronto Stock Exchange:

Series I Debentures: PWI.DB.A

Series II Debentures: PWI.DB.B

For More Information

General Inquiries: (403) 234-6600

Investor Relations

Toll-free: 1-877-968-7878

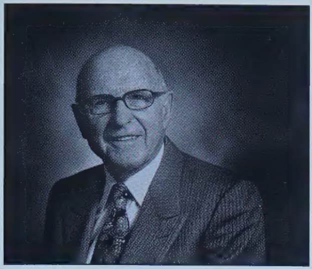
Fax: (403) 699-7477

Email: investor@primewestenergy.com

For additional information, please visit our website at:

www.primewestenergy.com

Board Of Directors



HAROLD P. MILAVSKY, B.Comm, CA, FCA,
Chair of the Board

Mr. Milavsky is Chair of the Board of Quantico Capital Corp., a privately held company engaged in merchant banking, principal investments and acquisitions. Mr. Milavsky also serves as a director, member of the Audit Committee and member of the Nominating/Corporate Governance Committee of Saskatchewan Wheat Pool and as a director, Chair of the Board and Chair of the Audit Committee of the 13 investment trusts comprising the Citadel Group of Funds™. Mr. Milavsky was President and CEO of Trizec Corporation from 1976 to 1986 and Chair of the Board and CEO from 1986 to 1993 and has acted as a director of many other corporations.

BARRY E. EMES, B.A., LL.B.

Mr. Emes is a Partner in the corporate/commercial group of the Calgary office of Stikeman Elliott LLP and served for seven years as a member of the firm's Partnership Board. Mr. Emes was previously employed by a Canadian chartered bank, and in the planning/economics group of a major international oil and gas company. Mr. Emes is a director of Parkbridge Lifestyle Communities Inc. and Graphamite Company (a private corporation).

HAROLD N. KVISLE, B.Sc., MBA, P.Eng.

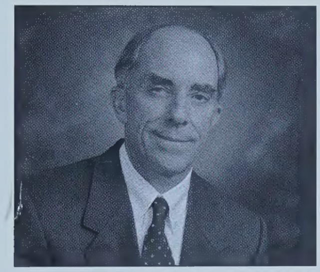
Mr. Kvisle is President, Chief Executive Officer and a director of both TransCanada Corporation and TransCanada Pipelines Limited and also serves as a director and member of the Human Resources and Management Compensation Committee of the Bank of Montreal. From October 1999 to May 2001, Mr. Kvisle was the Executive Vice President, Trading and Business Development of TransCanada Pipelines Limited.

KENT J. MACINTYRE, B.Sc. Eng., MBA

Mr. MacIntyre is Chair of the Board of Canadian Income Fund Group Inc., a private company engaged in capital origination and principal investment activities in the financial services and energy areas. With more than 25 years of oil and gas experience, Mr. MacIntyre has acted as a principal to the formation and start-up of a number of companies, including PrimeWest (having held the office of Vice-Chair of the Board and CEO from inception in 1996 until his retirement in 2003) and the 13 investment trusts comprising the Citadel Group of Funds™, for which he also serves as a director. Mr. MacIntyre is a director of a number of other corporations.

MICHAEL W. O'BRIEN B.A., MBA

Mr. O'Brien serves as director and Chair of the Audit Committee of Shaw Communications Inc., and as a director, member of the Audit Committee and member of the Environmental, Health & Safety Committee of Suncor Energy Inc. Mr. O'Brien is past Chair of the Canadian Petroleum Products Institute, Canada's Voluntary Challenge Registry for Climate Change and the Nature Conservancy of Canada. From March 1995 to June 2002, Mr. O'Brien was the Executive Vice President, Corporate Development and CFO of Suncor Energy Inc.



JAMES W. PATEK, B.Sc., M.Sc.

Mr. Patek is the President of Patek Energy Consultants, based in the U.S. He was previously CEO of Petrocorp Exploration Limited, CEO of Fletcher Challenge Energy, Senior Reservoir Engineer at Conoco, Division Engineer and Division Manager of Husky Oil Operations Limited and Operations Manager at Petrocorp Exploration Limited. Prior to June 2000, Mr. Patek was President of Fletcher Challenge Energy Canada.

W. GLEN RUSSELL, B.Sc., P.Eng.

Mr. Russell, principal of Glen Russell Consulting, serves as a director and Chair of the Board of Evoco Inc. (a private corporation) and is a director, Chair of the Board, Chair of the Corporate Governance and Human Resources Committee and member of the Operations and Reserves Committee of Petro Andina Resources Inc. (a private corporation in Argentina). He was previously President and COO of Chauvco Resources Limited and Senior Vice President and COO of Gulf Canada Resources Limited. Mr. Russell has also acted as Executive Advisor with regard to mergers and acquisitions and corporate strategy for a major Canadian investment banking firm.

PETER VALENTINE, B.Comm., FCA, ICD.D

Mr. Valentine is Senior Advisor to the President and CEO of the Calgary Health Region and to the Dean of Medicine at the University of Calgary. He is a Trustee, a member of the Audit Committee and a member of the Governance Committee of Fording Canadian Coal Trust, a director and Chair of the Audit Committee of Livingston International Income Fund, a director and member of the Audit Committee of Superior Plus Income Fund and a director and Chair of the Audit Committee of Resmor Trust Company (a private corporation). Mr. Valentine was previously the Auditor General for the Province of Alberta (March 1995 to January 2002) and a member of a number of other commissions, boards and institutes.

Officers*

DONALD A. GARNER
President and Chief Executive Officer

TIMOTHY S. GRANGER
Chief Operating Officer

DENNIS G. FEUCHUK
Vice-President, Finance and Chief Financial Officer

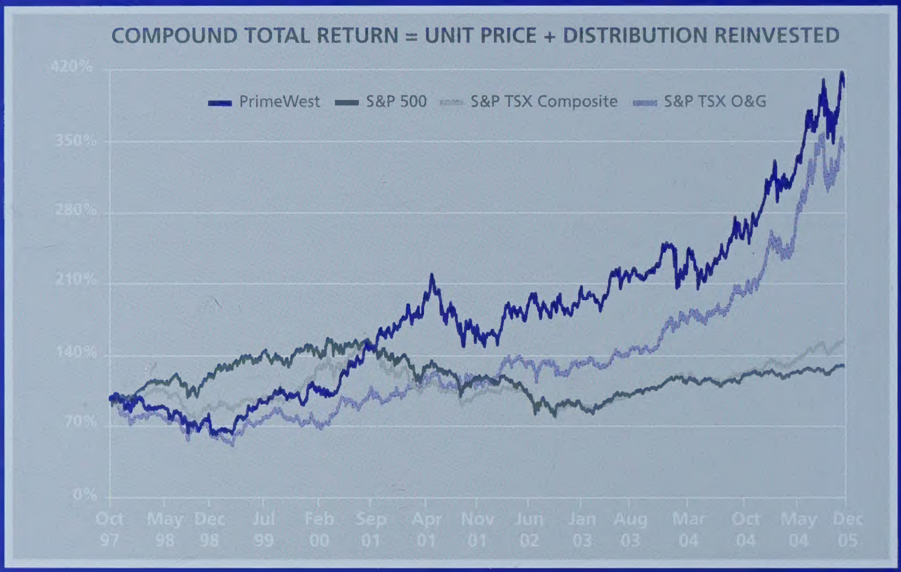
RONALD J. AMBROZY
Vice-President, Business Development

BRIAN J. LYNAM
Vice-President, Operations

* *Effective February 23, 2006, the Board of Directors appointed Mr. Gord Haun, Corporate Counsel and Secretary, to the position of General Counsel and Corporate Secretary and an Officer of PrimeWest.*

Please refer to the Trust's 2005 Renewal Annual Information Form for the complete biography of each director.

P R I M E W E S T



www.primewestenergy.com

PRIMEWEST ENERGY TRUST

HEAD OFFICE: 5100 150 6 Avenue S.W. Calgary Alberta Canada T2P 3Y7

GENERAL INQUIRIES: (403) 234-6600 FAX: (403) 699-7477 TOLL-FREE: 1 (877) 968-7878 EMAIL: investor@primewestenergy.com

TRUST UNITS, EXCHANGEABLE SHARES AND CONVERTIBLE DEBENTURES TRADED:

TSX: (PWI.UN, PWX, PWI.DB.A, PWI.DB.B); NYSE (PWI)